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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

{x} ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED) For the fiscal year ended December 31, 1999

For the fiscal year ended December 31, 1999

{ } TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

{ } For the transaction period from _______ to _______

Commission File Number 0-9592

RANGE RESOURCES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware (State of incorporation)	**34-1312571** (I.R.S. Employer Identification No.)
500 Throckmorton Street, Ft. Worth, Texas (Address of principal executive offices)	**76102** (Zip Code)

Registrant's telephone number, including area code:
(817) 870-2601

Securities registered pursuant to Section 12(b) of the Act:
None

Common Stock, $.01 par value
(Title of class)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No__

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. {X}

The aggregate market value of voting stock of the registrant held by non-affiliates (excluding voting shares held by officers and directors) was $75.6 million on March 13, 2000. Indicate the number of shares outstanding of each of the registrant's classes of stock on March 13, 2000: Common Stock $.01 par value: 39,847,179; Preferred Stock $1 par value: 1,025,140.

DOCUMENTS INCORPORATED BY REFERENCE:

Part III of this report incorporates by reference the Proxy Statement relating to the Registrant's 2000 Annual Meeting of Stockholders.

RANGE RESOURCES CORPORATION

Annual Report on Form 10-K
Year Ended December 31, 1999

PART I

ITEM 1. BUSINESS

General

Range Resources Corporation ("Range") is engaged in the acquisition, development and financing of oil and gas properties primarily in the Southwest (Permian and Midcontinent), Gulf Coast and Appalachian regions of the United States. The Company seeks to build value primarily through lower-risk development drilling and acquisitions while to a lesser degree pursuing higher risk exploitation and exploration projects on its extensive inventory of undeveloped acreage. Through its wholly owned subsidiary, Independent Producer Finance ("IPF"), the Company also provides financing to small oil and gas producers by purchasing term overriding royalty interests in their properties. The Company concentrates its activities in geographic areas in which it seeks to establish operating, engineering, geological, land and acquisition expertise. At December 31, 1999, the Company had 616.7 Bcfe of proved reserves, having a pre-tax present value of $555.6 million at constant prices of $23.48 per barrel and $2.34 per Mcf. On volumetric basis, the reserves were 72% natural gas and 80% operated by the Company. As of December 31, 1999, the Company's properties had a reserve life index of over 11 years.

Due to the adverse impact of two sizeable acquisitions consummated in 1997 and 1998, the Company has been forced to retrench over the past 18 months. Subsequent to these purchases, production has fallen and further development of each property has generally proved disappointing. In combination with the steep fall in oil and gas prices between late 1997 and early 1999, the substantial debt incurred by the Company in the acquisition transactions and the decline in stock prices of independent oil companies during the same period, the impact on the Company's results, balance sheet and market value has been severe. Sharp reductions in staff and capital budgets, a series of divestitures, the formation of the Great Lakes joint venture, the write-off of a significant portion of the book value of the Company's properties and the exchange of common equity for some of the Company's convertible securities have stabilized the situation. The Company has set an internally funded capital budget for the coming year designed to provide modest production growth while permitting excess cash flow to reduce the Company's debt. However, additional progress, particularly in reducing debt and associated fixed charges, will be necessary before the Company is in the position to return to its historical posture of consistent profitability and growth.

In September 1999, Range and FirstEnergy Corp. ("FirstEnergy") contributed their Appalachian oil and gas properties and associated gas pipeline systems to a joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes"). To achieve equal ownership in the venture, Range contributed $188.3 million of indebtedness and FirstEnergy contributed $2.0 million of cash. Great Lakes expects to increase its production and reserves through development of existing fields, exploitation of deeper formations underlying its properties and the pursuit of acquisition opportunities in Appalachia.

Description of the Business

Strategy

The Company primarily pursues lower risk development drilling and acquisitions while, to a lesser degree, engages in higher risk exploitation and exploration of its properties. Over the past ten years, total assets have grown from $6 million to $752 million at year end 1999. During this same period of time, stockholders' equity increased from $1 million to $127 million. In 1997 through 1999, the Company incurred losses totaling $206 million, which materially reduced total assets and stockholders' equity. In 2000, the

Company’s goal is to reduce debt as a percentage of capitalization by cutting costs, selling non-strategic assets and limiting exploration and development expenditures. The Company currently expects to use any proceeds from asset sales to reduce outstanding bank debt. While the current 2000 capital budget is anticipated to provide modest growth in production, management believes that the cost reductions, the sale of assets, and the capital restructuring should position Range to pursue growth initiatives in 2001.

The Company currently has over 2,100 proven recompletion and development drilling projects in inventory. Given the recent rebound in oil and gas prices and its extensive inventory of development projects, the Company believes it can achieve growth in reserves, production, cash flow and earnings over the next several years if it can reduce its debt burden. The Company currently anticipates spending approximately $45.0 million during 2000 on development and exploration activities. The Company’s leasehold position currently approximates 1.8 million gross acres (0.9 million net), providing significant long-term development and exploration potential.

To effectively implement its operating strategy, the Company has concentrated its activities in selected geographic areas. In these areas, the Company has established separate business units, each with operating, engineering, geological, land and acquisition expertise. The Company believes this focus provides a competitive advantage in sourcing and evaluating new opportunities, as well as providing economies of scale in operating and developing existing properties.

Development. The Company’s development activities include recompletions of existing wells, infill drilling and installation of secondary recovery projects. Development prospects are generated within core areas where the Company has significant operational and technical experience. At December 31, 1999, 1,750 proven undeveloped locations and 376 recompletion opportunities were in inventory. The Company currently plans to perform 56 recompletions and drill 177 development wells in 2000.

Exploration. Beginning in 1996, the Company began to explore on or near its existing properties. Range currently has domestic onshore exploration projects covering 573,500 gross (110,100 net) acres. The Company’s onshore exploration program targets deeper horizons within existing fields, as well as establishing new fields in trend areas in which its technical staff has experience. Range’s offshore exploration program focuses on the shallow waters of the Gulf of Mexico where it holds 3D seismic data covering 3.5 million contiguous acres. Range has offshore leases covering 50,500 gross acres on which it has to date identified 15 projects. Range’s strategy is based upon limiting its risk by allocating no more than 10% to 20% of its capital budget to exploration, allowing other companies to pay for the Company’s costs in order to earn an interest in our exploratory projects, and by participating in a variety of projects. The Company currently anticipates participating in drilling 22 exploratory wells in 2000.

Acquisitions. The Company’s acquisition strategy has historically been based on: (i) Locale: focusing in core areas where the Company has operating and technical expertise; (ii) Efficiency: targeting acquisitions which the Company believes offer the possibility of operating and cost efficiencies, (iii) Reserve Potential: pursuing properties which the Company believes have the potential for reserve increases through recompletions and drilling; (iv) Incremental Purchases: seeking acquisitions where opportunities may exist for purchasing additional interests in the same or adjoining properties; and (v) Complexity: pursuing more complex but less competitive corporate acquisitions. In an effort to reduce debt, the Company expects to limit itself to pursuing incremental purchases during 2000.

Development and Exploration Activities

During 1999, the Company spent $37.4 million on oil and gas related capital expenditures. This represented a sharp reduction from the $81.5 million expended in 1998. Of this total, $9.4 million was expended in the Southwest, $3.9 million in Appalachia and $24.1 million in the Gulf Coast. The expenditures in 1999 were primarily focused on converting proved but non-producing reserves into producing reserves. These expenditures funded 41 recompletions, 45 development wells and 11 exploratory wells, as well as a minor amount spent to acquire leases and seismic data. Exploration and development spending converted 34.9 Bcfe of non-producing reserves to the producing category production and added 12.9 Bcfe of new reserves. Reserves added during the year replaced 19% of production.

Development Activities

The Company's development activities include recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. As described below, the Company currently has 2,126 proven recompletion opportunities and drilling locations in inventory. Those wells are geographically diverse and target a mix of oil and gas in formations generally at depths of less than 8,000 feet. Approximately 95% of the development wells are concentrated in 12 fields covering 687,900 gross (528,605 net) acres. The Company believes that such large acreage blocks and concentration of wells will provide economies of scale, access to competitively priced oil field services and focused operating and technical expertise. The following table sets forth information pertaining to the Company's proven development inventory at December 31, 1999.

	Number of Development Projects		
	Recompletion Opportunities	**Drilling Locations**	**Total**
Southwest	263	241	504
Gulf Coast	66	31	97
Appalachia	47	1,478	1,525
Total	376	1,750	2,126

Exploration Activities

Domestic Onshore. Range currently has fifteen onshore exploration projects covering 573,500 gross (110,100 net) acres. Each project has multiple drilling prospects, some with multiple targets. Given the Company's current capital constraints, only a limited amount of work will be done on these projects in the coming year.

Gulf of Mexico. Range has a 3D seismic database covering 700 contiguous blocks in the shallow waters of the Gulf of Mexico, primarily offshore Louisiana. This database has been used to map geological trends within this 3.5 million acre area, identifying specific targets for further exploration. The Company's current offshore leasehold inventory totals 50,500 gross (15,155 net) acres and to fully exploit the 3D seismic data base it will be necessary for the Company to farm-in or lease significant additional acreage. To date, 14 prospects have been identified. These prospects target the Miocene formation at depths of 8,000 to 18,000 feet. Due to the Company's current financial position, exploitation of the exploratory potential of these properties has been largely deferred. As a result, the Company did not participate in any offshore exploratory wells in 1999.

Production

Production revenue is generated through the sale of oil, natural gas liquids and gas from properties owned directly or through partnerships and joint ventures. The Company receives additional revenue from royalties on oil and gas production properties the Company leases to third parties. While production is sold to a limited number of purchasers, only two account for more than 10% of oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the business. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices at which production can be marketed. Factors outside the Company's control such as political developments in the Middle East, overall energy supply and demand, weather conditions and economic growth rates and other economic factors in the United States and world economies have had, and will continue to have, a significant effect on energy prices.

The following table sets forth historical production volumes, revenue and expense information for the past five years (in thousands, except average sales price and operating cost data).

	Year Ended December 31,				
	1995	**1996**	**1997**	**1998**	**1999**
Production					
Crude oil (Bbl)	913	1,018	1,371	2,175	2,247
Natural gas liquids (Bbl)	—	50	423	480	412
Gas (Mcf)	12,471	21,231	38,409	45,193	50,808
Total (Mcfe) (a)	17,949	27,641	49,170	61,120	66,763
Revenues					
Crude oil (Bbl)	$15,133	$19,912	$ 24,967	$ 26,119	$ 33,075
Natural gas liquids (Bbl)	—	513	3,833	3,965	4,302
Gas	22,284	47,629	101,217	105,509	108,115
Total	$37,417	$68,054	$130,017	$135,593	$145,492
Average Sales Price					
Crude oil (Bbl)	$ 16.57	$ 19.56	$ 18.22	$ 12.01	$ 14.72
Natural gas liquids (Bbl)	—	$ 10.22	$ 9.06	$ 8.26	$ 10.43
Gas (Mcf)	$ 1.79	$ 2.24	$ 2.64	$ 2.33	$ 2.13
Mcfe (a)	$ 2.08	$ 2.46	$ 2.64	$ 2.22	$ 2.18
Average Operating Cost Per Mcfe (a)	$ 0.63	$ 0.75	$ 0.64	$ 0.64	$ 0.65

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.

On a Mcfe basis, approximately 76% of 1999 production was natural gas. Gas production was sold to utilities, marketing companies or directly to industrial users. Gas sales are made pursuant to various arrangements ranging from month-to-month contracts, one to three year contracts at fixed or variable prices and contracts at fixed prices for the life of the well. All contracts other than the fixed price contracts contain provisions for price adjustment, termination and other terms customary in the industry. A number of the Appalachian gas contracts are at prices that compare favorably to the current spot market, although this may change over time. Oil is sold on a basis such that the contract can be terminated on 30 days notice. The price received is generally equal to a posted price at which major purchasers in the area are willing to pay for oil. Oil purchasers are selected on the basis of price and service. In 1999, revenues from gas sales totaled $108 million or 74% of total oil and gas revenues while revenues from oil and natural gas liquids production amounted to $37 million, representing 26% of the total. Oil and gas revenues in 1999 increased 7% over the prior year level.

Gas Transportation, Processing and Marketing

Gas transportation, processing and marketing revenues are comprised of fees for the transportation of production through gathering lines and fees from gas processing as well as income from marketing of oil and gas. Transportation, processing and marketing revenues increased 16% in 1999 to $7.8 million versus $6.7 million in 1998.

The Company’s natural gas transportation and processing assets are comprised of (i) 50% ownership in approximately 4,700 miles of gas transportation and gathering pipelines in Appalachia held through the Great Lakes joint venture, (ii) nearly 300 miles of gathering lines and a gas processing plant in the Sterling area of the Permian Basin and (iii) a number of smaller transportation and gathering systems associated with existing producing properties. The Appalachian gathering systems transport a majority of Great Lakes’ gas production as well as third party gas to major trunklines and directly to industrial end-users. Third parties who transport their gas through the systems are charged a fee based on throughput. In its Southwest and Gulf Coast areas, the Company transports its gas production through a combination of Company-owned and third party gathering systems. The Company is typically charged a fixed fee per volume of production to transport its gas through third party systems. The Company's Sterling gas processing plant is a refrigerated turbo-expander cryogenic gas plant that was placed in service in 1995. In September 1999, the Sterling gas processing plant was put up for sale. The Company anticipates completing the sale of the plant in the second quarter of 2000, with proceeds going to reduce debt.

To maximize the value of its production, the Company began marketing its own gas production in 1993. The Company has managed the impact of potential price declines by developing a balanced portfolio of fixed price and market sensitive contracts and commodity hedging. Approximately 12% of its gas production is currently sold pursuant to fixed price sales contracts. These contracts are at prices ranging from $1.50 to $3.85 per Mcf. Contracts with terms of less than one year and greater than five years constitute approximately 99% and 1%, respectively, of the volume sold under fixed price contracts.

Periodically, the Company enters into option and swap contracts to reduce the effects of fluctuations in crude oil and natural gas prices. At December 31, 1999, the Company had open hedges covering 24.8 Bcf of natural gas and 0.8 million barrels of oil. While these transactions have no carrying value, the fair value of these transactions (represented by the estimated amount that would be required to terminate the contracts), was a net gain of approximately $0.3 million at December 31, 1999. The gas contracts were at prices ranging from $2.00 to $3.17 per Mmbtu and the oil contracts range from $19.01 to $25.00 per Bbl. Gains or losses on hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on NYMEX. Resulting gains or losses are determined monthly and included in the revenues in the period the hedged production is sold. Net gains (losses) relating to these derivative transactions for the year ended December 31, 1998 and 1999, approximated $3.1 million and $(10.6) million, respectively. In the future, the Company may hedge a larger percentage of its production, however, it currently anticipates that such percentage would not exceed 80% during any rolling twelve month period. Although hedging provides the Company some protection against falling prices, these activities also reduce the potential benefits of price increases.

Independent Producer Finance ("IPF")

IPF provides capital to small oil and gas producers to finance acquisition and development projects. IPF advances money in exchange for a term overriding royalty interest in the projects being financed. The overrides are dollar-denominated and are calculated to provide IPF with a contractually specified rate of return that typically ranges between 15% and 25%. Most of IPF's advances are for less than $5 million. IPF funds its business through a combination of internal cash flow and bank borrowings. At December 31, 1999, IPF's portfolio included 61 transactions having an aggregate book value of $65.4 million (net of $17.3 million of allowances). The reserves and present value of the reserves underlying IPF advances are not included in Range's consolidated oil and gas reserve disclosure. IPF provides allowances for advances, which may be unrecoverable. These allowances reduce IPF's reported revenues. During 1999, IPF provided $3.3 million in allowances, which reduced its reported revenues from $11.2 million to $7.9 million. IPF expenses in 1999 included $1.5 million of general and administrative costs and $4.3 million of interest expense At current commodity prices, the Company believes that IPF's bad debt reserves are adequate.

IPF has three petroleum engineers and geologists who identify and evaluate projects. These personnel all hold degrees in petroleum engineering or geology. The staff averages 17 years of experience in operations, strategic planning, analysis and production engineering. The professionals are responsible for defining transaction risk, establishing reserve coverage and negotiating the contractual rate of return. IPF structures the transactions with a goal to minimize risk by focusing on asset coverage ratios and taking direct title to the overriding royalty interests. As dollar-denominated term overriding royalties, the transactions leave much of the commodity price risk with the producer.

IPF provides capital to small oil and gas producers who are generally ignored by traditional financial institutions. These producers typically are denied access to traditional financing arrangements because: (i) they are too small to access public debt and equity markets; (ii) private equity and debt financing is too restrictive and expensive; and (iii) few commercial banks are interested in small energy loans; as consolidation in the banking industry has raised the size threshold for lending. IPF's portfolio decreased in 1999 as a limited number of fundings were more than offset by principal repayments. The Company expects demand for IPF funding to rise, as oil and gas acquisition and divestiture activities continue and consolidation of the banking industry reduces the supply of traditional bank financing for small transactions. IPF's bank debt is recourse only to the assets of IPF. In December 1999, IPF established a new revolving credit facility. The $100 million facility had an initial borrowing base of $56 million. On March 13, 2000, $42.4 million was borrowed under the facility.

IPF investments involve an up-front cash payment for the purchase of a term overriding royalty interest pursuant to which IPF receives an agreed upon share of revenues from specific properties. The producer's obligation to IPF is non-recourse. The producer generally is only liable if he fails to operate prudently, there is a title failure or certain other events occur which are within the producer's control. Consequently, IPF's ability to successfully invest is based on its ability to accurately estimate the volumes of recoverable reserves from which the applicable production payment is dedicated, the price at which the production will be sold, and the operator's ability to recover the reserves on a time schedule with the projected production rates. Because IPF's interest constitutes a property interest, if a producer is declared bankrupt or insolvent, our interest should be outside of the reach of the producer's creditors. However, if a creditor, the producer as debtor-in-possession or a trustee for the producer in a bankruptcy proceeding were to argue successfully that the transaction should be characterized as a loan, we may have only a creditor's claim for repayment of the amounts advanced. Our ownership in these production payments is a non-operating interest. As a result, our ownership of these production payments are likely to not expose us to liability resulting from the ownership of direct working interests, such as environmental liabilities and liabilities for personal injury or death or property damage. Finally, the producer's obligation to deliver a specified share of revenues to us is subject to the ability of the burdened reserves to produce such revenues. As a result, IPF bears the risk that revenues received will be insufficient to amortize the purchase price IPF paid for the property interest or to provide IPF an acceptable return.

IPF was acquired effective August 1998 with the Merger. The following table summarizes IPF's historical investments:

	Periods ended December 31,				
	1995	**1996**	**1997**	**1998**	**1999**
Total dollars of advances	$5,489	$19,100	$40,150	$45,822	$4,259
Number of advances made	10	27	39	75	30
Average size of advance	$ 549	$ 707	$ 1,029	$ 611	$ 142

Interest and Other

The Company earns interest on its cash and investment accounts, as well as on various receivables. Other income in 1999 was comprised principally of gains on sales of marketable equity securities and gains on sales of non-strategic properties. The Company expects to continue to sell properties that are not strategic. Interest and other income in 1999 amounted to $40.2 million, representing 20% of total revenues. Interest and other income included a $39.8 million proportional gain recognized on the Great Lakes transaction (See Note (17) – Gain on Sale).

Competition

The Company encounters substantial competition in acquiring oil and gas leases and properties, marketing oil and gas, securing personnel and conducting its drilling and field operations. Many competitors have financial and other resources, which substantially exceed those of the Company. The competitors in development, exploration, acquisitions and production include the major oil companies in addition to numerous independents, individual proprietors and others. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. The ability of the Company to replace and expand its reserve base in the future will depend on its ability to select and acquire suitable producing properties and prospects for future drilling.

The Company's acquisitions have been largely financed through issuances of debt and equity securities and internally generated cash flow. There is competition for capital to finance oil and gas acquisitions and drilling. The ability of the Company to obtain such financing on satisfactory terms is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise external capital in the future could have a material adverse effect on its business.

Governmental Regulation

The Company's operations are affected in varying degrees by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are or have been subject to price controls, taxes and other laws and regulations relating to the oil and gas industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the Company's cost of doing business and affects its profitability. Although the Company believes it is in substantial compliance with all applicable laws and regulations, because such laws and regulations are frequently amended or reinterpreted, the Company is unable to precisely predict the future cost or impact of complying with such laws and regulations.

Capital Restructuring Program

As a result of two significant acquisitions completed in 1997 and 1998 financed principally with debt and fixed rate convertible securities and due to the poor performance of the acquired properties as well as the significant drop in oil and gas prices between late 1997 and 1999, the Company undertook a number of initiatives. These include a reduction in workforce, a significant decrease in capital expenditures, the sale of assets, the formation of the Great Lakes joint venture and the exchange of Common Stock for fixed rate securities. These initiatives resulted in the Company reducing its parent company bank debt in 1999 by over 60% to $140 million at year end. Total debt was reduced 24% during 1999 to $459 million. While management believes these actions have stabilized the Company's financial position, debt to total capitalization at December 31, 1999 remained high at 65%. For the Company to return to its historical posture of consistent profitability and growth, management believes it is necessary for the Company to further reduce debt and associated fixed financing costs. In addition to further asset sales, the Company currently anticipates it will significantly increase its efforts to exchange Common Stock or other equity linked securities for its existing fixed rate securities or reduce debt and associated financing costs through some other substantial restructuring initiative. While the Company expects to exchange the fixed rate securities at a substantial discount to their face value, the Company's existing common stockholders will be materially diluted if a material portion of the fixed rate securities are exchanged. The dilutive effect to the common stockholders will depend upon a number of factors, the primary ones being the number of shares and the price at which additional Common Stock is issued or the price which newly issued securities are convertible into Common Stock. While a restructuring would reduce the existing stockholders' proportional ownership of the Company, management believes that a restructuring would substantially increase its ability to enhance the value of the Company as well as the market value of the Common Stock. Any substantial restructuring will require mutually satisfactory agreements with a large majority of the parties holding the Company's existing convertible securities. Additionally, to insure that a sufficient number of shares of Common Stock are available, it is likely that the Company's stockholders would need to approve increasing the number of authorized shares of Common Stock. While the Company currently projects that it has sufficient liquidity and cash flow to meet its obligations, a drop in oil and gas prices or further reduction in production and reserves will reduce the Company's ability to fund capital expenditures and meets its obligations. This could have a detrimental effect on the Company's ability to complete its capital restructuring program in a timely manner.

Environmental Matters

The Company's oil and natural gas exploration, development, production and pipeline gathering operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection.

Numerous governmental departments such as the Environmental Protection Agency ("EPA") issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and pipeline gathering activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from the Company's operations. In addition, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect the Company's operations and financial position, as well as the oil and gas industry in general. While management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and the Company has not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this will continue in the future. The Company did not have any material capital expenditures in connection with environment regulation in 1999, nor does it anticipate any material such expenditures in 2000.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and natural gas wastes are also pending in certain states, and these various initiatives could have a significant impact on the Company.

Stricter standards in environmental legislation may be imposed in the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain oil and natural gas exploration and production wastes as "hazardous wastes" and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Compliance with environmental requirements generally could have a material adverse effect upon the capital expenditures, earnings or competitive position of the Company. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue in the future.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal (NPDES) permits prohibit or are expected to prohibit within the next year the discharge of produced water and sand, and some other substances related to the oil and gas industry, to coastal waters. Although the costs to comply with zero discharge mandated under federal or state law may be significant, the entire industry will experience similar costs and the Company believes that these costs will not have a material adverse impact on the Company’s financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Resources Conservation and Recovery Act (“RCRA”), as amended, generally does not regulate most wastes generated by the exploration and production of oil and natural gas. RCRA specifically excludes from the definition of hazardous waste “drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy.” However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, the Company does not expect to experience more burdensome costs than similarly situated companies involved in oil and gas exploration and production.

In addition, the U.S. Oil Pollution Act (“OPA”) requires owners and operators of facilities that could be the source of an oil spill into “waters of the United States” (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

Risk Factors and Cautionary Statement for purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

Certain information included in this report, other materials filed or to be filed by the Company with the SEC, as well as information included in oral statements or other written statements made or to be made by the Company contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words “budget,” “budgeted,” “assumes,” “should,” “goal,” “anticipates,” “expects,” “believes,” “seeks,” “plans,” “estimates,” “intends,” “ or “projects” and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date of this report is filed with the Securities and Exchange Commission, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, and our ability to implement our business strategy. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph.

With the previous paragraph in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

Current common shareholders will be diluted as more common shares are issued.

The Company has filed a shelf registration statement to allow the Company to issue additional common stock. The Company in 1999 and in early 2000 has exchanged its common stock for its 5.75% trust convertible preferred securities, 6% convertible debentures, and $2.03 convertible exchangeable preferred stock. Such exchanges have been made based upon the relative market value of common stock and the market value of convertible security at the time of the exchange with a five to eight percent premium. The convertible securities were acquired at 35% to 68% discounts to the face value of such securities. The exchanges will reduce interest expense, dividends and the Company’s future repayment obligations. However, the larger number of common shares outstanding and any additional shares issued in the future will have a dilutive effect on the existing shareholders of the Company.

The Company has announced that the Company is actively reviewing alternatives to restructure the Company’s balance sheet to reduce the amount of future obligations under the Company’s convertible securities. The Company expects under any alternative selected that a large number of the Company’s common stock will have to be issued to retire or purchase such securities. Therefore, the actual number of shares issued for such securities less the face value of the securities retired will dilute the current shareholders.

The Company intends to change the capital structure

The Company currently anticipates it will significantly increase its efforts to exchange common stock or other equity linked securities for its existing fixed income securities. While the Company expects to exchange the fixed rate securities at a substantial discount to their face value, the Company’s existing common stockholders will be materially diluted if a material portion of the fixed income securities are exchanged.

The dilutive effect to the common shareholders will depend upon a number of factors. The primary ones are (a) the number of shares issued, and (b) the price of the additional common stock issued or the price that newly issued securities are convertible into common stock. Any significant restructuring would reduce the existing stockholders’ proportional ownership of the Company. However, management believes that a restructuring could substantially increase management’s ability to enhance the value of the Company as well as the market value of the common stock. It is expected that any significant restructuring will require both the agreement of the existing stockholders and those parties holding the existing convertible securities. Additionally, the Company’s stockholders would need to approve increasing the number of authorized shares of common stock to insure that a sufficient number of shares of common stock are available under a restructuring plan.

While the Company currently projects that it has sufficient liquidity and cash flow to meet its obligations, a drop in oil and gas prices or further reduction in production and reserves will reduce the Company’s ability to fund capital expenditures and meets its obligations. Any of these occurrences could have a detrimental effect on the Company’s ability to complete its capital restructuring program in a timely manner.

The Company’s ability to change its capital structure and the terms which we are able to make any changes is dependent on a variety of factors beyond our control such as the level and differentials of various interest rates, the willingness of other parties to engage in transactions, state and federal regulations covering such transactions, and the overall economic conditions in the capital markets assessable by the Company.

Payment of dividends are restricted

Restrictions on the payment of dividends on the Company’s $2.03 convertible exchangeable preferred stock and common stock are contained in the Company’s senior secured bank debt and the 8.75% senior subordinated notes.

Under terms of the 8.75% Senior Subordinated Notes, the Company may pay restrictive payments, which includes dividends. The restrictive payments may equal the higher of $20 million or a formula, which include earnings and losses since the issuance of the senior subordinated notes. Given the Company's losses since 1997, the Company can not pay dividends under the formula and, therefore, must rely on the initial $20 million basket amount. At December 31, 1999, $12.7 million of the $20 million basket had been used thus leaving $7.3 million available under the basket for payment of dividends.

Oil and gas prices are volatile, which can adversely affect cash flow available for reinvestment.

Prices for oil and gas are volatile. The oil and gas industry can be highly cyclical and historically has experienced severe downturns characterized by oversupply and weak demand. Many factors affect the prices for our oil and gas production including general economic conditions, consumer preferences, discretionary spending levels, interest rates and the availability of credit and capital to provide new production. During the latter part of 1998 and early 1999, oil and gas prices were significantly lower than the prices that we are currently receiving. This was a factor in those periods when we reported substantial losses. Decreases in oil and gas prices from current levels will adversely affect our revenues, results of operations, cash flows and proved reserves. If the industry experiences significant and prolonged price decreases in the future, this could have a materially adverse effect on our operations and could result in our inability to fund planned capital expenditures.

Our hedging activities expose us to certain risks.

We enter into hedging arrangements relating to a portion of our oil and gas production to achieve more predictable cash flow, insure a level of cash flow to fund our capital spending plans, as well as to reduce our exposure to adverse price fluctuations of oil and gas. Hedging instruments used include fixed price swaps, collars, calls, and options. While the use of these types of hedging instruments limits our exposure to adverse price movements, they are subject to a number of risks, including limiting the benefit of commodity price increases and the nonperformance financial risks of the other party accepting our hedge.

Estimates of our oil and gas reserves may change; we may not be able to replace reserves

The calculations of our proved oil and gas reserves included in this document are only estimates. The accuracy of any reserve estimate is a function of the quality of available data; engineering and geological interpretation and judgment; the assumptions used regarding quantities of recoverable oil and gas reserves; and prices for oil and gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will vary from those assumed in our estimates, and such variances may be significant. If the assumptions used to estimate our reserves later prove to be incorrect in any way, the actual quantity of our reserves and future net cash flow could be materially different from the estimates in our reserve reports. In addition, results of drilling, testing, and producing with changes in oil and gas prices after the date of the estimate may result in substantial upward or downward revisions.

Without successful exploration, development or acquisition activities, our reserves and revenues will decline over time. Exploration, the continuing development of our reserves and acquisition activities will require significant expenditures. If our cash flow from operations is not sufficient for this purpose, we may not be able to obtain the funds from other sources necessary to continue such exploration, development and acquisition activities.

We may have write downs of oil and gas properties' carrying value

Accounting rules require that we periodically review the carrying value of our oil and gas properties for possible impairment. An "impairment" is recognized when the unamortized cost of a property included on the Company's balance sheet is greater than the expected undiscounted future cash flows from the property. We may be required to write down the carrying value of our oil and gas properties based on specific market factors and circumstances at the time of the prospective impairment review, and the continuing evaluation of development plans, production data, economics and other factors. A write down constitutes a current non-cash charge to earnings generally associated with costs spent in prior years. An impairment charge does not impact our cash flow from operating activities.

Based primarily on our long-term outlook for future commodities prices and the production performance of certain properties, we recorded impairment charges of $197 million in 1998 and $27 million in 1999. For a further discussion of our accounting policies with respect to oil and gas properties, see Note 1 to the Consolidated Financial Statements.

We could incur substantial environmental liabilities

Our industry is subject to numerous federal, state and local laws and regulations relating to environmental protection. We may incur significant costs and liabilities in complying with existing or future environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and enforcement policies thereunder, and claim for damages to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. For additional information concerning environmental matters, see the “Environmental Matters” section included in this report.

Our activities involve operating hazards and uninsured risks

While we maintain insurance against certain of the risks normally associated with our operations, including, but not limited to explosion, pollution and fires, the occurrence of a significant event against which we are not fully insured could have a significant negative effect on our business. Such occurrences could include title defects on properties owned or acquired from others, lost equipment in drilling operations which our drilling contractor is not responsible for such loss, costs to redrill wells due to down hole equipment and casing failures, and property damage caused over a period of time not covered by standard industry insurance policies.

We maintain insurance policies covering our operations in amounts and areas of coverage normal for a company of our size in the oil industry. These include, but are not limited to, workers’ compensation, employers’ liability, automotive liability and general liability. In addition, umbrella liability and operator’s extra expense policies are maintained. All such insurance is subject to normal deductible levels. We do not insure against all risks associated with our business either because insurance is not available or because we have elected not to insure due to prohibitive premium costs or other considerations.

In today’s legal climate, a number of individuals or companies may feel that the Company or those acting on behalf of the Company damaged or harmed such parties either physically or financially. Such parties have the right under the law to seek recovery of those damages in court. Since the likelihood of the results of the verdict or judgment of the courts are uncertain, the Company may elect to settle such claims outside the judicial system. Those settlements may not be covered by insurance and such payments might have to be borne solely by the Company. The Company may elect to contest such claims but still be held liable by the courts. Many times the cost of defending oneself or the costs incurred defending the rights of the Company cannot be recovered from the other parties. Such legal and out of pocket costs must be borne solely by the Company and included in its general and administrative expenses. Such costs and settlements could have a material effect on our earnings. See Item 3 “Legal Proceedings” included in this report and Note 8 to Consolidated Financial Statements as to certain proceedings and contingencies of the Company.

We are subject to financing and interest rate exposure risks

Our business and operating results can be harmed by factors such as the availability or cost of capital, changes in interest rates, changes in the tax rates due to new tax laws, market perceptions of the oil and gas industry or the Company, or any reduction in our credit ratings. These changes could cause our cost of doing business to increase or limit our ability to exploit opportunities in the market place.

We face stiff competition

We face competition in all aspects of our business, including, but not limited to, acquiring reserves, leases, obtaining goods, services, and labor needed to conduct operations and manage the Company, and marketing oil and gas. Our competitors include multinational energy companies, other independent producers and individual producers and operators. Many of our competitors have greater financial and other resources than the Company.

Crude oil and natural gas are subject to extensive regulation

The petroleum industry is subject to various types of regulations in the United States by local, state and federal agencies. Domestic legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both state and federal, are authorized by statute to issue and have issued rules and regulations binding on the oil and gas industry and its individual members. Compliance with such rules and regulations is often difficult and costly and may carry substantial penalties for non-compliance. As the regulatory burden on the oil and gas industry increases, the cost of doing business affects profitability. Generally these burdens do not appear to affect the Company any differently or to any greater or lesser extent than other companies in the industry with similar types, quantities and location of production. While we are a party to several regulatory proceedings before governmental agencies arising in the ordinary course of business, we do not believe that the outcome of such proceedings will have a material adverse effect on our operations or financial condition.

Our level of fixed charges could have important consequences to our liquidity, profitability and cash flow

The Company has a significant amount of annual fixed charges associated with senior secured bank debt, 8.75% senior subordinated notes, 6% convertible debentures, non-recourse bank debt of subsidiaries, 5.75% trust convertible preferred securities and $2.03 convertible exchangeable preferred stock. As of December 31, 1999, the aggregate face values of such obligations were $605 million and the associated fixed charges at the rates in effect at December 31, 1999 were $47.3 million per year. Such obligations have certain requirements that the Company must comply with in order for such obligations to remain due and payable as disclosed in Note 6 to the Consolidated Financial Statements. Violations to such requirements could accelerate the maturity of such obligations and have a material adverse effect on the financial viability of the Company.

The significant indebtedness of the Company could have other important consequences to the Company’s intended business plan and financial viability such as, but not limited to, the required sale of assets at unfavorable prices to reduce debt, increase in interest rates which would require more of the Company’s cash flow and result in less capital spent on developing and acquiring new oil and gas properties, limit the Company’s ability to raise capital both in the equity and debt markets, limit or prohibit certain financing options available to less leveraged companies, and make the Company more vulnerable during periods of low oil and gas prices.

Risks associated with our IPF program may affect our revenues

Our Independent Producer Finance (“IPF”) program involves an up-front cash payment for the purchase of a term overriding royalty interest through which we receive an agreed upon share of revenues from identified properties. The producer’s obligation to deliver these revenues to us is non-recourse to the producer meaning that IPF can only recover its investment and return through revenues generated by the identified properties. The producer generally is not liable to us for any failure to meet its payment obligation unless the producer fails to operate prudently, there is a title failure or certain other events within the producer’s control occur. Consequently, our ability to realize returns and advances on our IPF investments is subject to our ability to accurately estimate the volumes of recoverable reserves from which the applicable production payment is to be discharged and the operator's ability to recover these reserves. Because our interest constitutes a property interest, if a producer is declared bankrupt or insolvent, our interest may be outside of the reach of the producer's creditors. However, if a creditor, the producer as debtor-in-possession or a trustee for the producer in a bankruptcy proceeding were to argue successfully that the transaction should be characterized as a loan, we may have only a creditor's claim for repayment of the amounts advanced. Our ownership in these production payments is a non-operating interest. As a result, our ownership of these production payments should not expose us to liability resulting from the ownership of direct working interests, such as environmental liabilities and liabilities for personal injury or death or property damage. Finally, the producer's obligation to deliver a specified share of revenues to us is subject to the ability of the burdened reserves to produce such revenues. As a result, IPF bears the risk that future revenues we receive will be insufficient to amortize the purchase price we paid for the interest or to provide any investment return to us.

Our past and future acquisitions may be subject to risks arising from ownership of real property

We intend to continue acquiring oil and gas properties. It generally is not feasible for us to review in detail every individual property we acquire. Ordinarily, our review efforts are focused on the higher-valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when we do perform an inspection.

Our Chairman has a business interest in another oil and gas company that could compete with our business

Our Chairman, Thomas J. Edelman, is also the Chairman and Chief Executive Officer and a significant shareholder of Patina Oil & Gas Corporation ("Patina"), a publicly traded oil and gas company and is an officer or significant investor in several other public and private companies engaged in various aspects of the energy industry. We currently have no business relationships with these companies, and none of them own any of our securities. However, as a result of Mr. Edelman's positions, conflicts of interests may arise. We have board policies that require Mr. Edelman to give us notification of any potential conflicts that may arise. However, we cannot assure you that we will not compete with one or more of these companies for the same acquisition or encounter other conflicts of interest.

Our success depends on key members of our management

The Company's success and failure will be highly dependent on a limited number of senior management personnel, none of which are subject to employment contracts. Loss of services of one or more of these individuals could have a material adverse effect on the Company's operations.

Employees

As of January 1, 2000, the Company had 136 full time employees, 58 of whom were field personnel. None are covered by a collective bargaining agreement and management believes that its relationship with its employees is good.

ITEM 2. PROPERTIES

On December 31, 1999, the Company held working interests in 9,893 gross (5,025 net) productive oil and gas wells and royalty interests in 587 additional wells. The properties contained, net to the Company's interest, estimated proved reserves of 443.8 Bcf of gas and 28.8 million barrels of oil and natural gas liquids or a total of 616.7 Bcfe. Included herein is the Company's fifty percent share of the reserves of the Great Lakes joint venture.

Proved Reserves

The following table sets forth estimated year-end proved reserves for each of the past five years.

	December 31,				
	1995	1996	1997	1998	1999
Natural gas (Mmcf)					
Developed	174,958	207,601	369,786	436,062	299,436
Undeveloped	57,929	87,993	204,632	197,255	144,345
Total	232,887	295,594	574,418	633,317	443,783
Oil and NGL (Mbbls)					
Developed	8,880	10,703	14,971	19,649	17,884
Undeveloped	1,983	3,972	14,803	7,480	10,933
Total	10,863	14,675	29,774	27,129	28,817
Total (Mmcfe) (a)	298,065	383,644	753,062	796,091	616,685

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.

In connection with the evaluation of its reserves, the Company engaged the following independent petroleum consultants: H.J. Gruy and Associates, Inc. (Southwest and Gulf Coast), DeGoyler and MacNaughton (Gulf Coast), and Wright and Company, Inc. (Appalachia). These engineers have been employed primarily based on geographic expertise as well as their history in engineering certain of the acquired properties. At December 31, 1999, independent petroleum consultants evaluated approximately 89% of the proved reserves set forth above. The remainder were evaluated by the Company's engineering staff. All estimates of oil and gas reserves are subject to significant uncertainty.

The following table sets forth for each of the past five years, the estimated future net cash flow from and the Present Value of the proved reserves in millions.

	December 31,				
	1995	1996	1997	1998	1999
Future net cash flow	$413	$941	$1,276	$1,020	$1,013
Present Value					
Pre-tax	229	492	632	555	556
After tax	174	351	511	517	503

Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. Such calculations, which are prepared in accordance with the Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" are based on cost and price factors at December 31, 1999. Average product prices in effect at December 31, 1999 were $23.48 per barrel of oil, $15.69 per barrel for natural gas liquids, and $2.34 per Mcf of gas using the benchmark NYMEX price of $25.60 per barrel and $2.33 per Mmbtu. There can be no assurance that the proved reserves will be developed within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of reserves have been filed with or included in reports to another federal authority or agency since December 31, 1999.

Significant Properties

The Company's reserves at December 31, 1999 were concentrated in three regions, Southwest, Gulf Coast and Appalachia. Properties in the Southwest region are divided into two divisions, Permian and

Midcontinent. The Appalachia properties represent the Company's 50% ownership in Great Lakes. At December 31, 1999, the Company's properties included working interests in 9,893 gross (5,025 net) productive oil and gas wells and royalty interests in 587 additional wells. The Company also held interests in 627,600 gross (239,626 net) undeveloped acres. The following table sets forth summary information with respect to the Company's estimated proved oil and gas reserves at December 31, 1999.

	Pre-tax Present Value				
	Amount (In thousands)	**%**	**Oil & NGL (Mbbls)**	**Natural Gas (Mmcf)**	**Total (Mmcfe)**
Southwest					
Permian	$204,853	37	19,585	87,211	204,715
Midcontinent	50,877	9	862	52,932	58,110
Subtotal	255,730	46	20,447	140,143	262,825
Gulf Coast	138,918	25	2,380	118,872	133,152
Appalachia	160,962	29	5,990	184,768	220,708
Total	$555,610	100	28,817	443,783	616,685

Southwest Region

The Company's Southwestern properties are situated in the Permian and Val Verde Basins of west Texas, the Texas panhandle, the East Texas Basin and the Anadarko Basin of western Oklahoma. Reserves in these basins represent 46% of total Present Value at December 31, 1999. Southwestern proved reserves totaled 263 Bcfe, of which approximately 53% were natural gas. At December 31, 1999, the Southwest Region properties had a development inventory of 504 recompletions and drilling locations.

Permian. The Permian division properties, located in the Permian and Val Verde Basins of west Texas, contained 205 Bcfe of proved reserves. These reserves, representing 37% of total Present Value, were 57% oil and natural gas liquids. In the fourth quarter of 1999, the Permian properties produced an average of 4,434 barrels of oil and NGL and 23.8 Mmcf of gas per day. Producing wells total 1,394 (655 net), of which the Company operates 88% on a total reserve basis. Major producing areas include the Sonora, Sterling, the Big Lake and Fuhrman-Mascho area, and Powell Ranch. The Oakridge and Frances Hill fields in the Sonora area produce from multiple deltaic channel Canyon sandstones at depths of 2,600 to 6,000 feet. At Sterling, gas production is derived from Canyon/Cisco sub-marine sand deposits at 4,000 to 8,000 foot depths, while oil production comes from Silurian Fusselman carbonates. Sterling area gas production is liquids-rich and is transported to the Company's 25,000 Mcf/d gas plant, which processes gas from the Company's operated properties, as well as gas produced by third parties. The Company is currently in negotiations to sell the Sterling Gas processing plant. It is anticipated that a sale will be closed in the second quarter of 2000. The Big Lake and Fuhrman-Mascho area produces primarily oil from the San Andres/Grayburg formations at depths ranging from 2,500 feet to 4,600 feet. The Powell Ranch area produces primarily oil from the Wolfcamp formation at a depth of 8,000 to 9,000 feet. At December 31, 1999, the Permian properties contained a development inventory of 227 recompletions and 207 infill drilling locations.

Midcontinent. The Midcontinent business division properties, located in the Anadarko Basin of western Oklahoma and the Texas panhandle, held proved reserves of 58 Bcfe at December 31, 1999. These reserves, representing 9% of the total Present Value, were 91% natural gas. Of 301 gross (190 net) wells, the Company operates 89%. The division's largest property is the Okeene Field, which includes 180 operated wells. In the fourth of quarter 1999 the Midcontinent properties produced an average of 156 barrels of oil and 16.1 Mmcf of gas per day. The properties produce from a variety of sands and carbonates in both structural and stratigraphic traps on the Hunton, Red Fork, Mississippi, Spring, and Morrow formations at 6,000 to 12,000 foot depths. The Midcontinent development inventory includes 36 recompletions and 34 drilling locations.

Gulf Coast Region

The Company's Gulf Coast properties include onshore reserves in south Texas, Louisiana and Mississippi, as well as, offshore reserves in the shallow waters of the Gulf of Mexico. The Gulf Coast business unit properties contained 133 Bcfe of proved reserves at December 31, 1999, or 25% of the total Present Value. The reserves were 89% natural gas. In the fourth quarter of 1999, daily production from the Gulf Coast properties averaged 1,294 barrels of oil and 43.0 Mmcf of gas per day. Major fields onshore include Alta Mesa and Oakvale. These fields produce from the Frio, Vicksburg, and Hosston formations at depths ranging from 1,000 to 16,000 feet. In total, the onshore properties include 87 wells (52 net), of which 89% are Company operated. The properties in the Gulf of Mexico include offshore interests in 51 platforms in water depths ranging from 20 to 400 feet. The Company does not operate any offshore wells. The entire Gulf Coast region is characterized by relatively complex geology, multiple producing horizons and substantial exploitation and exploration potential. At December 31, 1999, the Gulf Coast properties had a development inventory of 66 recompletions and 31 drilling locations.

Appalachian Region

At December 31, 1999, the Company's 50% ownership in Great Lakes represented a net 221 Bcfe of proved reserves, or 29% of the Company's total Present Value. The reserves are attributable to 7,999 gross wells (6,610 net wells) located in Pennsylvania, Ohio, West Virginia, New York, and Michigan. Great Lakes operates 93% of these wells. The reserves, which on an Mcfe basis, are 84% natural gas, produce principally from the Upper-Devonian, Medina, Clinton, Knox and Oriskany formations at depths ranging from 2,500 to 7,000 feet. In the fourth quarter of 1999, the Company's share of daily production averaged 29.1 Mmcf of gas and 697 barrels of oil. After initial flush production, these properties are characterized by gradual decline rates. Gas production is transported through over 4,700 miles of Company owned gas gathering systems and is sold primarily to FirstEnergy and, to lesser the extent, other third parties. Under the arrangement with FirstEnergy, Great Lakes' sells gas to FirstEnergy on a negotiated basis. Great Lakes may sell gas to third parties, however such arrangements are contracted through FirstEnergy, and FirstEnergy may elect to match any such arrangements. At December 31, 1999, Great Lakes had a development inventory of 47 recompletions and 1,478 drilling locations.

The management of the joint venture is directed by a committee of three representatives each from the Company and FirstEnergy. Any disagreements among the committee are resolved through arbitration.

Production

The following table sets forth production information for the preceding five years (in thousands, except average sales price and operating cost data).

	Year Ended December 31,				
	1995	1996	1997	1998	1999
Production					
Crude oil (Mbbl)	913	1,018	1,371	2,175	2,247
Natural gas liquids (Mbbl)	—	50	423	480	412
Gas (Mmcf)	12,471	21,231	38,409	45,193	50,808
Total (Mmcfe) (a)	17,949	27,641	49,170	61,120	66,763
Revenues					
Crude oil	$15,133	$19,912	$ 24,967	$ 26,119	$ 33,075
Natural gas liquids	—	513	3,833	3,965	4,302
Gas	22,284	47,629	101,217	105,509	108,115
Total	37,417	68,054	130,017	135,593	145,492
Direct operating expenses (b)	11,302	20,676	31,481	39,001	43,074
Gross Margin	$26,115	$47,378	$ 98,536	$ 96,592	$102,418
Average Sales Price					
Crude oil (Bbl)	$ 16.57	$ 19.56	$ 18.22	$ 12.01	$ 14.72
Natural gas liquids (Bbl)	—	$ 10.22	$ 9.06	$ 8.26	$ 10.43
Gas (Mcf)	$ 1.79	$ 2.24	$ 2.64	$ 2.33	$ 2.13
Mcfe (a)	$ 2.08	$ 2.46	$ 2.64	$ 2.22	$ 2.18
Average Operating Cost Per Mcfe (a)	$ 0.63	$ 0.75	$ 0.64	$ 0.64	$ 0.65

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.

(b) Includes severance and production taxes.

Producing Wells

The following table sets forth information relating to productive wells at December 31, 1999. The Company owns royalty interests in an additional 587 wells. Wells are classified as oil or gas according to their predominant production stream.

	Gross Wells	Net Wells	Average Working Interest
Crude oil	2,049	1,518	74%
Natural gas	7,844	3,507	45%
Total	9,893	5,025	51%

Acreage

The following table sets forth developed and undeveloped acreage held at December 31, 1999.

	Gross	Net	Average Working Interest
Developed	1,185,126	631,789	53%
Undeveloped	627,607	239,626	38%
Total	1,812,733	871,415	48%

Drilling Results

The following table summarizes drilling activities for the three years ended December 31, 1999.

	Year Ended December 31,					
	1997		1998		1999	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	186.0	164.1	222.0	182.0	43.0	20.6
Dry	7.0	5.4	12.0	8.8	3.0	1.7
Exploratory wells:						
Productive	12.0	2.8	9.0	3.9	1.0	0.5
Dry	8.0	2.0	5.0	2.9	3.0	0.8
Total Wells:						
Productive	198.0	166.9	231.0	185.9	44.0	21.1
Dry	15.0	7.4	17.0	11.7	6.0	2.5
Total	213.0	174.3	248.0	197.6	50.0	23.6

Real Property

The Company owns a 24,000 square foot facility located on seven acres in Ohio, which it leases to Great Lakes under a standard office lease arrangement, the term of which ends on September 30, 2000. Great Lakes has an option to purchase the facility during the lease term for $1.2 million. At the end of the lease term, the Company currently plans to sell the facility to either Great Lakes or a third party purchaser. The Company leases approximately 56,000 square feet in Texas and Oklahoma under standard office lease arrangements that expire at various times through March 2004. All facilities are adequate to meet the Company's current needs and existing space could be expanded or additional space could be leased.

The Company owns various vehicles and other equipment that is used in its field operations. Such equipment is believed to be in good repair and, while such equipment is important to its operations, it can be readily replaced as necessary.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims will be resolved without a material adverse effect on the Company's financial position.

In May 1998, a Domain stockholder filed an action in the Delaware Court of Chancery, alleging that the terms of the merger with Range were unfair to a purported class of Domain stockholders and that the defendants (except Range) violated their legal duties to the class in connection with the merger. Range is alleged to have aided and abetted the breaches of fiduciary duty allegedly committed by the other defendants. The action sought an injunction enjoining the merger as well as a claim for money damages. In 1998, the parties executed a Memorandum of Understanding (the "MOU"), which represents a settlement in principle of the litigation. Under the terms of the MOU, appraisal rights (subject to certain conditions) were offered to all holders of Domain common stock (excluding the defendants and their affiliates). Domain also agreed to pay any court-awarded attorneys' fees and expenses of the plaintiffs' counsel in an amount not to exceed $0.3 million. The settlement in principle is subject to court approval and certain other conditions.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR THE COMMON STOCK AND RELATED MATTERS

The Company's common stock is listed on New York Stock Exchange ("NYSE") under the symbol "RRC". Prior to August 25, 1998, the stock was listed under the symbol "LOM". During 1999, trading volume averaged 199,400 shares per day. On March 13, 2000, the closing price of the Common Stock was $2.00. The following table sets forth the high and low sales prices as reported on the NYSE Composite transaction tape on a quarterly basis for the periods indicated.

	High	Low	Common Dividends
1998			
First Quarter	$17 1/2	$13 1/4	$.03
Second Quarter	16 11/16	9 3/4	.03
Third Quarter	10 7/16	6 1/16	.03
Fourth Quarter	6 13/16	2 15/16	.03
1999			
First Quarter	$3 3/4	$1 7/8	$.01
Second Quarter	7	2 9/16	.01
Third Quarter	6 1/2	4 1/8	.01
Fourth Quarter	4 5/8	2 9/16	.00

The Company's $2.03 convertible exchangeable preferred stock 5.75% trust convertible preferred securities, and 6% convertible debentures and 8.75% senior subordinated notes are not listed on any exchange, but trade over the counter.

Holders of Record

At March 13, 2000 the number of holders of record of the common stock and $2.03 convertible exchangeable preferred stock were approximately 2,543 and 1, respectively.

Dividends

Dividends on the common stock were initiated in late 1995, were paid in each quarter through 1998, reduced and paid through the third quarter of 1999. In the fourth quarter of 1999, common dividends were suspended as the Company focused on reducing debt. The Convertible Preferred Stock is entitled to receive cumulative quarterly dividends at the annual rate of $2.03 per share. If there is any arrearage in dividends on preferred stock, the Company may not pay dividends on the common stock. The Company has never been in arrears in the payment of preferred dividends.

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and market factors existing from time to time. The bank credit facility and the indenture for the 8.75% Senior Subordinated Notes contain restrictions on the Company's ability to pay dividends on capital stock. Under the most restrictive of these provisions, the Company could pay $7.3 million of additional dividends as of December 31, 1999.

Under terms of the 8.75% Senior Subordinated Notes, the Company may pay restrictive payments, which includes dividends. The restrictive payments may equal the higher of $20 million or a formula that include earnings and losses since the issuance of the senior subordinated notes. Given the Company's losses since 1997, the Company can not pay dividends under the formula and, therefore, must rely on the initial $20 million basket amount. At December 31, 1999, $12.7 million of the $20 million basket had been used thus leaving $7.3 million available under the basket for payment of dividends.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information covering the preceding five years.

	As of or for the Year Ended December 31,				
	1995	1996	1997	1998	1999
	(In thousands, except per share data)				
Operations					
Revenues	$ 41,169	$ 75,341	$145,417	$ 148,929	$201,364
Net income (loss)	4,390	12,615	(23,332)	(175,150)	(7,793)
Earnings (loss) per share before extraordinary items — basic	.31	.71	(1.31)	(6.82)	(0.34)
Earnings (loss) per share before extraordinary items — dilutive	.31	.69	(1.31)	(6.82)	(0.34)
Earnings (loss) per share – basic	.31	.71	(1.31)	(6.82)	(0.27)
Earnings (loss) per share – dilutive	.31	.69	(1.31)	(6.82)	(0.27)
Dividends per common share	0.01	0.06	0.10	0.12	0.03
Balance Sheet					
Working capital	$ 4,563	$ 12,896	$ (2,051)	$ (9,484)	$ 19,291
Oil and gas properties, net	176,702	229,417	623,807	662,099	595,297
Total assets	214,788	282,547	758,833	921,612	752,368
Senior debt	83,035	61,780	186,712	367,062	140,000
Non-recourse debt	—	—	—	60,100	142,520
Subordinated debt	—	55,000	180,000	180,000	176,360
Trust convertible preferred securities	—	—	120,000	120,000	117,669
Stockholders' equity	99,367	117,529	196,950	133,222	127,171

The following table sets forth summary unaudited financial information on a quarterly basis for the past two years (in thousands, except per share data).

	1998			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$ 36,010	$ 32,273	$ 35,431	$ 45,215
Net income (loss) (a)	2,769	(944)	(66,907)	(110,068)
Earnings (loss) per share – basic (a)	.10	(.07)	(2.57)	(3.13)
Earnings (loss) per share – dilutive (a)	.10	(.07)	(2.57)	(3.13)
Total assets (a)	800,252	822,984	1,036,111	921,612
Senior debt	234,905	252,200	368,176	367,062
Non-recourse debt	—	—	53,795	60,100
Subordinated notes	180,000	180,000	180,000	180,000
Trust convertible preferred securities	120,000	120,000	120,000	120,000
Stockholders' equity(a)	199,058	195,747	234,575	133,222

	1999			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues (c)	$ 37,953	$ 42,196	$ 81,095	$ 40,121
Net income (loss) (b)(c)	(8,981)	(2,087)	12,722	(9,446)
Earnings (loss) per share – basic (b)(c)	(0.26)	(0.07)	0.33	(0.27)
Earnings (loss) per share – dilutive (b)(c)	(0.26)	(0.07)	0.33	(0.27)
Total assets (b)	905,522	895,677	775,785	752,368
Senior debt	317,451	317,085	146,650	140,000
Non-recourse debt	60,100	54,200	146,755	142,520
Subordinated debt	180,000	176,360	176,360	176,360
Trust convertible preferred securities	120,000	117,669	117,669	117,669
Stockholders' equity(b)(c)	124,886	125,970	137,090	127,171

(a) Includes a $97.9 million provision for impairment ($63.6 million after tax) recorded in the third quarter and a $109.2 million provision for impairment ($92.6 million after tax) recorded in the fourth quarter.

(b) Includes a $20.9 million provision for impairment that was recorded in the third quarter and $6.1 million in the fourth quarter.

(c) Includes a proportional gain associated with the Great Lakes Energy Partners, see Note 17 to the financial statements.

The total of the earnings per share for each quarter does not equal the earnings per share for the full year, either because the calculations are based on the weighted average shares outstanding during each of the individual periods, or due to rounding.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Factors Effecting Financial Condition and Liquidity

Liquidity and Capital Resources

The following discussion compares the Company's financial condition at December 31, 1999 to its financial condition at December 31, 1998. During 1999, the Company spent approximately $38.3 million on acquisition, development and exploration activities. At December 31, 1999, the Company had $12.9 million in cash and total assets of $752.4 million. During 1999, debt decreased from $607.2 million to $458.9 million. At December 31, 1999, debt to total book capitalization was 65%.

Long-term debt at December 31, 1999 included $140 million of borrowings under the Credit Facility, $95.0 million under the non-recourse Great Lakes Facility, $47.5 million under the non-recourse IPF Facility, $125.0 million of 8.75% Senior Subordinated Notes and $51.4 million of 6% Convertible Subordinated Debentures. The Company's balance on its Credit Facility was reduced 62% from $365.2 million at December 31, 1998 to $140.0 million at December 31, 1999. Including the debt exchanges noted below, total debt fell from $607.2 million at December 31, 1998 to $458.9 million at December 31, 1999.

In September 1999, Range and FirstEnergy each contributed all of their Appalachia oil and gas properties and associated gas gathering and transportation systems to form Great Lakes. In addition, Range contributed $188.3 million of indebtedness and FirstEnergy contributed $2.0 million in cash. Great Lakes expects to increase production by active development of existing fields and exploitation of deeper formations. Great Lakes also intends to pursue acquisition opportunities in Appalachia. Range and FirstEnergy each retained a 50% ownership interest in Great Lakes. The Company pro rata consolidates 50% of the assets and liabilities of Great Lakes.

During 1999, Range exchanged $2.3 million of Convertible Preferred Securities and $3.6 million of Debentures for approximately 699,000 shares of Common Stock. In connection with the exchanges, a $2.4 million extraordinary gain was recorded as the securities were retired at a discount to their face value. See Capital Restructuring Program below.

In September 1999, the Company elected to pursue the sale of its gas processing plant and associated assets located in the Permian Basin. In connection with the plan of disposal, the Company determined that the carrying value of the plant exceeded its fair value. Accordingly, an impairment loss of $21.0 million was recorded which represented the excess of the carrying value over the estimated fair value. Fair value of the gas processing plant was estimated by reference to the present value of the estimated future cash inflows of the gas processing plant. The impairment estimate on the gas processing plant recorded in the third quarter 1999 was based on estimates of future cash flows for the property. Future cash flows include revenues from residue gas, plant liquids and by-products derived from both equity and third party proved natural gas reserves, which are estimated to pass through the plant, direct operating costs and capitalized costs. The Company estimated future gas prices by referencing ten year futures strip prices in the calculation of the plant revenues estimated over the anticipated life of the property. These prices are adjusted for the effect of the estimated throughput production, subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the date of the impairment charge. Based upon discussions with potential acquirers of the gas processing plant, the Company believes that the carrying value of the plant does not exceed its fair market value. The Company's Credit Facility provides that the borrowing base will be reduced by 67% of the net proceeds of the sale of the Sterling gas plant.

The Company currently estimates that its capital resources are adequate to meet the requirements of its business. However, future cash flows are subject to a number of variables including the level of production and oil and gas prices and other world economic conditions that have historically affected the oil and gas production and exploration business. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures. See Capital Restructuring Program below.

Cash Flow

The Company's principal operating sources of cash include sales of oil and gas, revenues from transportation and processing and IPF revenues. The Company's cash flow is highly dependent upon oil and gas prices. Decreases in the price of oil and gas and lower production attributable to certain properties during 1999 reduced cash flow and resulted in the reduction of the borrowing base under the Credit Facility. As a result, the Company reduced its development and exploration spending to $37.4 million in 1999. The 1999 expenditures were entirely funded by internally generated cash flow.

The Company's net cash provided by operations for the years ended December 31, 1997, 1998 and 1999 was $77.1 million, $45.0 million and $52.6 million, respectively. The decrease in the Company's cash flow from operations is attributed primarily to lower energy prices, and increased interest expense for amounts outstanding under the Credit Facility.

The Company's net cash used in (provided by) investing for the years ended December 31, 1997, 1998 and 1999 was $501.1 million, $172.3 million and $(95.8) million, respectively. Investing activities for these periods are comprised primarily of additions to oil and gas properties through the Company's investment in Great Lakes, acquisitions and development, proceeds of sale of assets, IPF investments and, to a lesser extent, exploration and additions of field service assets. The Company's activities have been financed through a combination of operating cash flow, bank borrowings and capital raised through equity and debt offerings.

The Company's net cash provided by (used in) financing for the years ended December 31, 1997, 1998 and 1999 was $425.2 million, $128.5 million and $(146.4) million, respectively. Sources of financing used by the Company have been primarily borrowings under its Credit Facility and capital raised through equity and debt offerings. During 1999, the Company decreased its parent company recourse debt by $231 million and total debt by $148.3 million. The reduction in debt was accomplished by the formation of Great Lakes, property sales and applying excess cash flow to debt repayment.

Capital Requirements

In 1999, $37.4 million of capital was expended on development and exploration activities. In an effort to reduce debt the Company significantly reduced its 1999 exploration and development capital budget from the $81.5 million expended in 1998. The budgeted 2000 development and exploration expenditures of $45 million are currently expected to be funded entirely by internally generated cash flow. The development and exploration activities are highly discretionary and are expected to be maintained at levels below internally generated cash flow. The remaining cash flow will be available for debt repayment. See "Business—Development and Exploration Activities."

Bank Facilities

The Company maintains a $225 million revolving bank facility (the "Credit Facility"). The Credit Facility provides for a borrowing base, which is subject to semi-annual redeterminations. The Credit Facility is secured by the Company's oil and gas properties. At March 13, 2000, the borrowing base on the Credit Facility was $160 million of which $16 million was available. The borrowing base is subject to semi-annual determination and certain other redeterminations based upon a variety of factors, including the discounted present value of estimated future net cash flow from oil and gas production. At the Company's option, loans may be prepaid and the revolving credit commitment may be reduced, in whole or in part at anytime in certain minimum amounts. The next redetermination occurs on April 1, 2000. If amounts outstanding at April 1, 2000 exceed the redetermined borrowing base, one-half of the excess, if any, must be repaid within 90 days and the remaining excess, if any, must be repaid within 180 days. Any borrowing base in excess of $135 million requires the approval of all lenders. There can be no assurance that a redetermined borrowing base will be in excess of $135 million. Therefore, the Company has classified as current the difference between the amount outstanding on December 31, 1999, and $135 million. A similar appropriate amount will be included in current portion of long term debt at March 31, 2000, unless an amended or replacement credit facility is entered into. Interest is payable quarterly or as LIBOR notes mature and the loan matures in February 2003. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50% depending upon the percentage of the borrowing base drawn. The interest rate on the Credit Facility is LIBOR plus between 1.50% and 2.25%, depending upon amounts outstanding. The weighted average interest rates on these borrowings were 6.7% and 7.1% for the years ended December 31, 1998 and 1999, respectively.

The Company pro rata consolidates 50% of amounts outstanding under the $275 million revolving bank facility (the “Great Lakes Facility”) through its ownership in Great Lakes. The Great Lakes Facility is non-recourse to Range. The Great Lakes Facility provides for a borrowing base, which is subject to semi-annual redeterminations. The Great Lakes Facility is secured by Great Lake’s oil and gas properties. At March 13, 2000, the borrowing base on the Great Lakes Facility was $191 million of which $9 million was available. On April 1, 2000, the borrowing base reduces to $190 million. The borrowing base is subject to a semi-annual borrowing review on April 1, 2000. Borrowing base redeterminations require the approval of all lenders. Interest is payable quarterly or as LIBOR notes mature and the loan matures in September 2002. The interest rate on the Great Lakes Facility is LIBOR plus between 1.50% and 2.00%, depending upon amounts outstanding. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50% depending upon the percentage of the borrowing base drawn. The weighted interest rate on this borrowing was 7.68% for the quarter ended December 31, 1999.

IPF has a $100 million revolving credit facility (the “IPF Facility”) through which it finances its activities. The IPF Facility is non-recourse to Range and matures in December 2002. The IPF Facility is secured by substantially all of IPF’s assets. The borrowing base under the IPF Facility is subject to a semi-annual redetermination on April 1, 2000. On March 13, 2000, the borrowing base on the IPF Facility was $56 million of which $13.6 million was available. The IPF Facility bears interest at prime rate or interest at LIBOR plus between 1.75% and 2.25%, depending on amounts outstanding. Interest expense on the IPF Facility is included in IPF expenses on the Consolidated Statements of Operations and amounted to $1.5 million and $ 4.3 million for the years ended December 31, 1998 and 1999, respectively. A commitment fee is paid quarterly on the average undrawn balance at a rate of 0.375% to 0.50%. The weighted average interest rate on these borrowings was 7.79% and 6.99% for the years ended December 31, 1998 and 1999, respectively.

The Company plans to reduce outstanding amounts under the Credit Facility through operating cash flow and the sale of assets. The Company classified $19.7 million of assets as held for sale at December 1999. These assets represent a gas processing plant and associated assets located in the Permian Basin, which are expected to be sold in the second quarter of 2000. The Company will use all of the proceeds from the sale of this plant, if consummated, to reduce amounts outstanding under the Credit Facility. Under terms of the Credit Facility, the borrowing base will be reduced by 67% of the proceeds from a sale. The Company is also considering the sale of other non-strategic assets whose proceeds would be used to reduce the Credit Facility. The Company’s goal is to sharply reduce debt as a percentage of total capitalization with the next twelve months. Additional asset sales may be necessary to reduce outstanding amounts under the Credit Facility to meet future borrowing base requirements, however, at this time, the Company has no agreements to sell any material assets other than those noted above.

Hedging Activities

Periodically, the Company enters into futures, option and swap contracts to reduce the effects of fluctuations in crude oil and natural gas prices. All futures, option and swap contracts entered into by the Company are solely to hedge the price volatility of oil and natural gas and not to speculate in the commodity markets. It is the Company’s policy to have no more than 80% of its production hedged in a twelve month period. At December 31, 1999, the Company had open hedges for natural gas of 24.8 Bcf and 0.8 million barrels of oil. The gas contracts are at average prices ranging from $2.00 to $3.17 per Mmbtu and the oil contracts range from $19.01 to $25.00 per Bbl. While these transactions have no carrying value, the

Company’s mark-to-market exposure under these contracts at December 31, 1999 was a net gain of approximately $0.3 million. These contracts expire monthly through December 2000. The gains or losses on the Company’s hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. The resulting transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains or (losses) relating to these derivatives for the years ended December 31, 1997, 1998 and 1999 approximated $(.9) million, $3.1 million and $(10.6) million, respectively.

Interest Rate Risk

At December 31, 1999, Range had debt outstanding of $458.9 million. Of this amount, $176.4 million, or 38% bears interest at fixed rates averaging 7.9%. The remaining $282.5 million of debt outstanding at the end of 1999 bears interest at floating rates which averaged 8.5% at the end of 1999. At December 31, 1999, the Company had $80 million of borrowings subject to four interest rate swap agreements at rates of 5.35%, 4.82%, 5.64% and 5.59% through January 2000, September 2000, October 2000 and October 2000, respectively. The interest rate swaps may be extended at the counterparties’ option for two years. The interest rate swap with a rate of 5.35% was not extended. The agreements require that the Company pay the counterparty interest at the above fixed swap rates and require the counterparty to pay the Company interest at the 30-day LIBOR rate. The closing 30-day LIBOR rate on December 31, 1999 was 6.49%. A 10% increase in short-term interest rates on the floating-rate debt outstanding at the end of 1999 would equal to approximately 85 basis points. Such an increase in interest rates would increase Range’s 2000 interest expense by approximately $2.4 million, assuming borrowed amounts remain constant throughout 2000. The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

Capital Restructuring Program

As a result of two significant acquisitions completed in 1997 and 1998 financed principally with debt and fixed rate convertible securities and due to the poor performance of the acquired properties as well as the significant drop in oil and gas prices between late 1997 and 1999, the Company undertook a number of initiatives. These include a reduction in workforce, a significant decrease in capital expenditures, the sale of assets, the formation of the Great Lakes joint venture and the exchange of Common Stock for fixed rate securities. These initiatives resulted in the Company reducing its parent company bank debt in 1999 by over 60% to $140 million at year end. Total debt was reduced 24% during 1999 to $459 million. While management believes these actions have stabilized the Company’s financial position, debt to total capitalization at December 31, 1999 remained high at 65%. For the Company to return to its historical posture of consistent profitability and growth, management believes it is necessary for the Company to further reduce debt and associated fixed financing costs. In addition to further asset sales, the Company currently anticipates it will significantly increase its efforts to exchange Common Stock or other equity linked securities for its existing fixed income securities or reduce debt and associated financing costs through some other substantial restructuring initiative. While the Company expects to exchange the fixed income securities at a substantial discount to their face value, the Company’s existing common stockholders will be materially diluted if a material portion of the fixed rate securities are exchanged. The dilutive effect to the common stockholders will depend upon a number of factors, the primary ones being the number of shares and the price at which additional Common Stock is issued or the price which newly issued securities are convertible into Common Stock. While a restructuring would reduce the existing stockholders’ proportional ownership of the Company, management believes that a restructuring would substantially increase its ability to enhance the value of the Company as well as the market value of the Common Stock. Any substantial restructuring will require mutually satisfactory agreements with a large majority of the parties holding the Company’s existing convertible securities. Additionally, to insure that a sufficient number of shares of Common Stock are available, it is likely that the Company’s stockholders would need to approve increasing the number of authorized shares of Common Stock. While the Company currently projects that it has sufficient liquidity and cash flow to meet its obligations, a drop in oil and gas prices or further reduction in production and reserves will reduce the Company’s ability to fund capital expenditures and meets its obligations. This could have a detrimental effect on the Company’s ability to complete its capital restructuring program in a timely manner.

Inflation and Changes in Prices

The Company’s revenues and the value of its oil and gas properties have been and will be affected by changes in oil and gas prices. The Company’s ability to maintain current borrowing capacity and to obtain additional capital on attractive terms is also dependent on oil and gas prices. Oil and gas prices are subject to significant seasonal and other fluctuations that are beyond the Company’s ability to control or predict. During 1999, the Company received an average of $14.72 per barrel of oil and $2.13 per Mcf of gas. Although certain of the Company’s costs and expenses are affected by the level of inflation, inflation did not have a significant effect in 1999. Should conditions in the industry improve, inflationary cost pressures may resume.

Results of Operations

Comparison of 1999 to 1998

The Company reported a net loss for the year ended December 31, 1999 of $7.8 million, as compared to a net loss of $175.2 million for 1998. Net income in 1999 includes a $2.4 million extraordinary gain on Convertible Preferred Securities and Debentures retired at a discount to their face value. Additionally, the Company recognized a $39.8 million proportional gain on the Great Lakes transaction (See Note 17- Gain on Sale).

Oil and gas revenues increased 7% to $145.5 million. During the year, oil and gas production volumes increased 9% to 66.8 Bcfe, an average of 182,900 Mcfe per day. The increased revenues recognized from production volumes were impacted by a 2% decrease in the average price received per Mcfe to $2.18. The average oil price increased 23% to $14.72 per barrel and average gas prices decreased 9% to $2.13 per Mcf. During 1999, the Company recorded gas revenues related to an above market gas contract with a utility company representing 2.8 Bcf of gas production at an average price of $3.81 per Mcf (approximately $10.6 million of gas revenue). Had this gas been sold on the same terms as other production was sold in the same geographical region (approximately $2.32 per Mcf), it would have resulted in a reduction in gas revenues of approximately $3.9 million. This gas contract expires June 30, 2000. If gas contracts cannot be found to replace the pricing received from this above-market contract, the Company will sell such gas at current market prices. Depending upon the market for natural gas at that time, this could have an adverse effect on the Company’s future revenues and liquidity. As a result of the Company’s larger base of producing properties and production, oil and gas production expenses increased 10% to $43.1 million in 1999 versus $39.0 million in 1998. The average operating cost per Mcfe produced was $0.64 during 1998 and $0.65 during 1999.

Transportation, processing and marketing revenues increased by $1.0 million to $7.8 million due to higher production levels. IPF income of $7.8 million consists of the interest portion of the term overriding royalty interest and is net of a $3.3 million allowance for possible uncollectible accounts. During 1999, IPF income expenses included $1.5 million of administrative expenses and $4.3 million of interest expense.

Exploration expense decreased $8.9 million to $2.4 million in 1999. During 1999 the Company significantly reduced exploration expenditures in an effort to reduce indebtedness and capital risk.

General and administrative expenses decreased 13% from $9.2 million in 1998 to $8.0 million in 1999. As a percentage of revenues, general and administrative expenses were 4.0% in 1999 as compared to 6.2% in 1998. The decrease was due to an overhead reduction program implemented late in 1998 and the sharing of services with Great Lakes.

Interest and other income increased $38.0 million to $40.2 million due to proportional gain recognized on the Great Lakes transaction (See Note (17) - Gain on Sale). Interest expense increased 16% to $47.1 million as compared to $40.6 million in 1998. This was primarily a result of the higher average outstanding debt balance during the year and a higher average cost of borrowing on the Credit Facility. The average outstanding balances on the Credit Facility were $272 million and $308 million for 1998 and 1999, respectively. The weighted average interest rate on these borrowings were 6.7% and 7.1% for the years ended December 31, 1998 and 1999, respectively.

Depletion, depreciation and amortization (“DD&A”) increased 27% compared to 1998 as a result of increased production volumes and lower proved reserves. The Company-wide depletion rate was $.89 per Mcfe in 1998 and $1.04 per Mcfe in 1999. In the third quarter of 1999, the Company recognized a $21 million impairment on a gas processing plant located in the Permian Basin. The book value of the plant was impaired to managements expectations of expected proceeds from the sale based upon preliminary discussions with potential buyers. The Company has decided to sell the plant and related assets and the net book value of these assets is classified as a current asset at December 31, 1999 on the Consolidated Balance Sheets (See Note (5) — Assets held for Sale). During 1999, the Company recorded $3.1 million of depreciation expense for the first nine months on its gas plant held for sale. In the fourth quarter of 1999, the Company recognized an impairment of $6.1 million on its unproved acreage value. Unproved properties are assessed periodically to determine whether there has been a decline in value. If such decline is indicated, a loss is recognized. The Company compares the carrying value of its unproved properties to the estimated present value of the future cash flows of unproved properties discounted at 10% or considers such other information the Company believes is relevant in evaluating the properties’ fair value. Such other information may include the Company’s geological assessment of the area, other acreage purchases in the area, or the properties’ uniqueness. The present value of future cash flows from such properties has been adjusted for the Company’s assessment of risk related to the unproved properties. In assessing the risk associated with unproved properties, the Company considers the recoverability of unproved reserves that have been classified as probable and possible reserves. Probable reserves are reserves not reasonably certain or proved, yet are “more likely to be recovered than not.” Additionally, in the fourth quarter, the Company adjusted the DD&A rate for changes in reserves and associated costs to $1.33 per Mcfe. Reserves were revised downward in 1999 due to sharper decline rates in production and reservoir pressures than previously estimated and after in-depth field evaluations. The Company currently estimates that its DD&A rate for 2000 will be approximately $1.25 per Mcfe. The higher DD&A rate makes it difficult for the Company to be consistently profitable.

Comparison of 1998 to 1997

The Company reported a net loss for the year ended December 31, 1998 of $175.2 million, as compared to a net loss of $23.3 million for 1997. Due to downward revisions on certain of its properties and the depressed energy price environment, the Company recorded a provision for impairment of $207.1 million ($156.2 million after tax) and $5.9 million ($5.0 million after tax) of valuation allowances on IPF receivables. The Company initiated a restructuring plan to reduce costs and improve operating efficiencies. In connection with the cost reduction program the Company recorded a charge of $3.1 million ($2.7 million after tax).

Oil and gas revenues increased 4% to $135.6 million. During the year, oil and gas production volumes increased 24% to 61.1 Bcfe, an average of 167.5 Mmcfe per day. The increased revenues recognized from production volumes were negatively impacted by a 16% decrease in the average price received per Mcfe of production to $2.22. The average oil price decreased 34% to $12.01 per barrel and average gas prices decreased 12% to $2.33 per Mcf. During 1998, the Company recorded gas revenues related to an above market gas contract with a utility company representing 4.0 Bcf of gas production at an average price of $3.77 per Mcf (approximately $15.1 million of gas revenue). Had this gas been sold on the same terms as other production was sold in the same geographical region ($3.16 per Mcf), it would have resulted in a reduction in gas revenues of approximately $2.4 million. This gas contract expires June 30, 2000. If gas contracts cannot be found to replace the pricing received from this above-market contract, the Company will sell such gas at current market prices. Depending upon the market for natural gas at that time, this could have an effect on the Company’s future revenues and liquidity. As a result of the Company’s larger base of producing properties and production, oil and gas production expenses increased 24% to $39.0 million in 1998 versus $31.5 million in 1997. The average operating cost per Mcfe produced was $0.64 during both periods.

Transportation, processing and marketing revenues decreased 14% to $6.7 million versus $7.8 million in 1997, the decrease was principally due to the sale of a gas processing plant in the San Juan Basin and a drop in natural gas liquid prices which lowered gas processing revenues. IPF income has been recorded for periods following the merger. IPF income consists of the interest portion of the term overriding royalty interests. During 1998, IPF expenses included $.5 million of administrative expenses, $1.6 million of interest expense and a $5.9 million valuation allowance.

Exploration expense increased 346% to $11.3 million due to the Company’s higher levels of seismic and exploratory drilling activity. During 1998 the Company spent $4.3 million on 5 exploratory dry holes compared to $0.3 million of dry hole costs in 1997.

General and administrative expenses increased 74% from $5.3 million in 1997 to $9.2 million in 1998. As a percentage of revenues, general and administrative expenses were 6.2% in 1998 as compared to 4% in 1997. The increase was due to higher personnel costs associated with the Company’s growth, as well as, increased legal expenditures during 1998. In December 1998, the Company implemented an overhead reduction program in response to the depressed energy price environment. The cuts included the termination of 54 employees, representing 27% of non-field staff.

Interest and other income decreased 70% to $2.3 million primarily due to lower levels of non-strategic assets sales. Interest expense increased 50% to $40.6 million as compared to $27.2 million in 1997. This was primarily a result of the higher average outstanding debt balance during the year due to the financing of acquisitions and drilling activities. The average outstanding balances on the Credit Facility were $192.1 million and $271.6 million for 1997 and 1998, respectively. The weighted average interest rate on these borrowings were 7.3% and 6.7% for the years ended December 31, 1997 and 1998, respectively.

Depletion, depreciation and amortization increased 9% compared to 1997 as a result of increased production volumes. This increase was partially offset by a decrease in the average depletion rate per Mcfe. The Company-wide depletion rate was $1.03 per Mcfe in 1997 and $.89 per Mcfe in 1998. During 1998, the Company recorded $5.5 million of depletion expense on properties classified as assets held for sale at year end.

The Company recorded a provision for impairment due to the effect that reserve revisions due to drilling results and depressed oil and gas prices had on its proved and unproved reserves during 1998. The following are the properties impaired during 1998 (in thousands):

Property	**Impairment Amount**
Sonora properties	$ 65,712
Sonora unproved acreage	20,089
Permian properties	1,018
West Texas properties	1,506
Gulf Coast properties	16,117
Michigan properties	14,644
East Texas properties	2,323
Matagorda Island	15,643
Mobile Bay	10,735
East & West Cameron	19,905
Offshore unproved acreage	9,177
South Texas unproved acreage	19,922
Marketable securities	10,337
	$207,128

Of the total impairment of $207.1 million, 45% was due to downward reserve revisions due to poor performance and drilling results and 55% was due to the decline in oil and gas prices. The impairment of oil and gas properties recorded in 1998 was based on estimates of future cash flows for each property in the two categories evaluated for impairment: proved properties and unproved properties. The impairment evaluation for proved properties utilized only proved reserves and the impairment evaluation for unproved properties utilized only unproved reserves. Future cash flows include revenues from anticipated oil and natural gas production, severance taxes, direct operating costs and capitalized costs. Unproved properties are assessed periodically to determine whether there has been a decline in value. If such decline is indicated, a loss is recognized. The Company compares the carrying value of its unproved properties to the present value of the future cash flows of unproved properties discounted at 10% or considers such other information the Company believes is relevant in evaluating the properties' fair value. Such other information may include the Company's geological assessment of the area, other acreage purchases in the area, or the properties' uniqueness. The present value of future cash flows from such properties has been adjusted for the Company's assessment of risk related to the unproved properties. In assessing the risk associated with unproved properties, the Company considers the recoverability of unproved reserves that have been classified as probable and possible reserves. Probable reserves are reserves not reasonably certain or proved, yet are "more likely to be recovered than not." Possible reserves are reasonably possible but "less likely to be recovered than not." The following is a table of index prices used in the calculation of the revenues estimated from oil and natural gas production over the anticipated life of the properties. These prices were then adjusted for the effect of the Company's production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges.

Year	Oil prices	Gas prices
1999	$ 12.62–13.25	$ 1.94-2.25
2000	14.50 – 16.00	2.23 - 2.30
2001	15.60 – 16.50	2.30 - 2.37
2002	16.44 – 17.10	2.35 - 2.44
2003	17.00 – 17.61	2.40 - 2.51
2004	17.50 – 18.14	2.45 - 2.59
2005	17.90 – 18.69	2.50 - 2.67
2006	18.35 – 19.25	2.58 - 2.75
2007	18.81 – 19.82	2.63 - 2.83
2008	19.28 – 20.42	2.69 - 2.91
2009	19.76 – 21.03	2.75 - 3.00

Severance taxes, direct operating costs and capitalized costs were estimated based on the Company's historical operating experience. These costs and expenses were escalated at 3% per year for 10 years and held constant thereafter. These prices were applied to production profiles developed by the Company's engineers using estimates of proved reserves and unproved reserves. The impairment estimates were determined based on the difference between the carrying value of the assets and the present value of future cash flows discounted at 10%. It is reasonably possible that a change in reserve or price estimates could occur in the near term and impact management's estimate of future cash flows and consequently the carrying value of properties.

At December 31, 1998, the Company compared the fair value of its available-for-sale marketable securities to their historical cost. Due to the fact that the fair values on certain individual securities were below their historical cost and the Company determined that these declines in value were other than temporary, it charged a $10.3 million impairment against these assets.

Comparison of 1997 to 1996

The Company reported a net loss for the year ended December 31, 1997 of $23.3 million, as compared to $12.6 million net income for 1996. During the fourth quarter of 1997, the Company recorded a provision for impairment with regard to certain of its oil and gas properties amounting to $58.7 million ($38.7 million after tax). Excluding the effects of the non-cash impairment charge, net income would have risen 22%

to $15.4 million. The increase is principally the result of (i) higher production volumes, (ii) lower per unit operating and overhead costs and (iii) higher average product prices. During the year, oil and gas production volumes increased 78% to 49.2 Bcfe, an average of 134.7 Mmcfe per day. The increased revenues recognized from production volumes were aided by an 7% increase in the average price received per Mcfe of production to $2.64. The average oil price decreased 7% to $18.22 per barrel while average gas prices increased 18% to $2.64 per Mcf. During 1997, the Company recorded gas revenues related to an above market gas contract with a utility company representing 6.0 Bcf of gas production at an average price of $3.73 per Mcf ($22.4 million of gas revenue). Had this gas been sold on the same terms as other production that was sold in the same geographical region, it would have resulted in a reduction in gas revenues of $8.1 million. This gas contract expires June 30, 2000. Depending upon the market for natural gas at that time, the possibility exists that the expiration of this contract could have a material effect on the Company’s future results of operations. As a result of the Company’s larger base of producing properties and production, oil and gas production expenses increased 52% to $31.5 million in 1997 versus $20.7 million in 1996. The average operating cost per Mcfe produced decreased 15% from $0.75 in 1996 to $0.64 in 1997.

Transportation, processing and marketing revenues increased 100% to $7.8 million versus $3.9 million in 1996 principally due to production growth. Exploration expense increased 73% to $2.5 million due to the Company’s increased involvement in seismic and exploratory drilling activity.

General and administrative expenses increased 33% from $4.0 million in 1996 to $5.3 million in 1997. As a percentage of revenues, general and administrative expenses were 4% in 1997 as compared to 5% in 1996. This decreasing trend reflects the spreading of administrative costs over a growing asset base.

Interest and other income rose 124% to $7.6 million primarily due to $3.2 million on gains from sale of marketable securities (which were not related to hedging activities), and $4.1 million from the gain on the sale of non-strategic assets. Interest expense increased 263% to $27.2 million as compared to $7.5 million in 1996. This was primarily as a result of the higher average outstanding debt balance during the year due to the financing of acquisitions and drilling activities. The average outstanding balances on the Credit Facility were $107.2 million and $192.1 million for 1996 and 1997, respectively. The weighted average interest rate on these borrowings were 6.7% and 7.3% for the years ended December 31, 1996 and 1997, respectively.

Depletion, depreciation and amortization increased 148% compared to 1996 as a result of increased production volumes and increased depletion rates per volume. The Company-wide depletion rate was $0.73 per Mcfe in 1996 and $1.03 per Mcfe in 1997.

The Company recorded a provision for impairment due to the effect that depressed oil and gas prices had on its proved reserves during 1997. The following are the properties impaired during 1997 (in thousands):

Property	**Impairment Amount**
Midcontinent properties	$16,538
Offshore properties	5,354
South Texas properties	10,022
Permian properties	26,786
	$58,700

Of the total impairment of $58.7 million, 24% was due to reserve revisions due to poor performance and drilling results and 76% was due to the decline in oil and gas prices. The impairment estimate recorded in 1997 was based on estimates of future cash flows for each property in the two categories evaluated for impairment: proved properties and unproved properties. The impairment evaluation for proved properties utilized only proved reserves and the impairment evaluation for unproved properties utilized only unproved reserves. Future cash flows include revenues from anticipated oil and natural gas production, severance taxes, direct operating costs and capitalized costs. Based on management's estimates, crude oil price estimates used to calculate these future net cash flows were based upon West Texas Intermediate posted price that was $16.00 per barrel for 1998 and was held constant thereafter. Natural gas price estimates were based upon NYMEX future price that was $2.15 per Mcf for 1998 and was held constant thereafter. These prices were then adjusted for the effect of the Company's production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges.

Severance taxes, direct operating costs and capitalized costs were estimated based on the Company's historical experience in its areas of operations. The impairment estimates were determined based on the difference between the carrying value of the assets and the present value of future cash flows discounted at 10%. It is reasonably possible that a change in reserve or price estimates could occur in the near term and adversely impact management's estimate of future cash flows and consequently the carrying value of properties.

Year 2000

Range has not experienced significant operational problems due to the Year 2000 issues. Range's significant suppliers, customers and service providers have been able to transact business on a normal basis in 2000 and there are no future problems anticipated that would materially impact Range's operations. The total cost for the Year 2000 Project did not exceed $0.2 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 40 for a listing of the Company's financial statements and notes thereto and for supplementary schedules. Schedules I, III, IV, V, VI, VII, VIII, IX, X, XI, XII and XIII have been omitted as not required or not applicable or because the information required to be presented is included in the financial statements and related notes.

Management Responsibility for Financial Statements

The financial statements have been prepared by management in conformity with generally accepted accounting principles. Management is responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

The Company maintains accounting and other controls which management believes provide reasonable assurance that financial records are reliable, assets are safeguarded, and that transactions are properly recorded. However, limitations exist in any system of internal control based upon the recognition that the cost of the system should not exceed benefits derived.

The Company's independent auditors, Arthur Andersen LLP, are engaged to audit the financial statements and to express an opinion thereon. Their audit is conducted in accordance with generally accepted auditing standards to enable them to report whether the financial statements present fairly, in all material respects, the financial position and results of operations in accordance with generally accepted accounting principles.

ITEM 9. CHANGE IN ACCOUNTANTS AND DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

The executive officers and directors of the Company are listed below, together with a description of their experience and certain other information. Each of the directors was elected for a one-year term at the Company's 1999 annual meeting of stockholders. Executive officers are appointed by the Board of Directors.

Name	Age	Held Office Since	Position With Company
Thomas J. Edelman	49	1988	Chairman and Chairman of the Board
John H. Pinkerton	45	1988	President, Chief Executive Officer and Director
Robert E. Aikman	67	1990	Director
Anthony V. Dub	50	1995	Director
Allen Finkelson	53	1994	Director
Ben A. Guill	49	1995	Director
Jonathan S. Linker	50	1998	Director
Eddie M. LeBlanc III	51	2000	Senior Vice President and Chief Financial Officer
Herbert A. Newhouse	54	1998	Senior Vice President – Gulf Coast
Chad L. Stephens	44	1990	Senior Vice President – Southwest
Rodney L. Waller	50	1999	Senior Vice President and Corporate Secretary
Michael V. Ronca	46	1998	Chief Operating Officer and Director (left the Company in February 2000)
Catherine L. Sliva	40	1998	Senior Vice President – Independent Producer Finance (resigned in January 2000)

Thomas J. Edelman, Chairman and Chairman of the Board of Directors, joined the Company in 1988. He served as its Chief Executive Officer until 1992. From 1981 to 1997, Mr. Edelman served as a director and President of Snyder Oil Corporation ("SOCO"), an independent, publicly traded oil and gas company. In 1996, Mr. Edelman was appointed Chairman and Chief Executive Officer of Patina Oil & Gas Corporation. Prior to 1981, Mr. Edelman was a Vice President of The First Boston Corporation. From 1975 through 1980, Mr. Edelman was with Lehman Brothers Kuhn Loeb Incorporated. Mr. Edelman received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from Harvard University's Graduate School of Business Administration. Mr. Edelman serves as a director of Paradise Music & Entertainment, Inc. and a director of the general partner of Star Gas Partners, L.P., a publicly-traded master limited partnership, which distributes fuel oil and propane gas.

John H. Pinkerton, President, Chief Executive Officer and a Director, joined the Company in 1988 as a Director. He was appointed President in 1990 and Chief Executive Officer in 1992. Previously, Mr. Pinkerton was Senior Vice President-Acquisitions of SOCO. Prior to joining SOCO in 1980, Mr. Pinkerton was with Arthur Andersen & Co. Mr. Pinkerton received his Bachelor of Arts Degree in Business Administration from Texas Christian University and his Master of Arts Degree in Business Administration from the University of Texas. Mr. Pinkerton is also director of Venus Exploration, Inc., a publicly traded exploration and production company in which Range owned 19% at December 31, 1999.

Robert E. Aikman, a Director, joined the Company in 1990. Mr. Aikman has more than 40 years experience in petroleum and natural gas exploration and production throughout the United States and Canada. From 1984 to 1994 he was Chairman of the Board of Energy Resources Corporation. From 1979 through 1984, he was the President and principal shareholder of Aikman Petroleum, Inc. From 1971 to 1977, he was President of Dorchester Exploration Inc. and from 1971 to 1980, he was a Director and a member of the Executive Committee of Dorchester Gas Corporation. Mr. Aikman is also Chairman of Provident Communications, Inc., President of OGP Technologies, Inc., and President of The Hawthorne Company, an entity which organizes joint ventures and provides advisory services for the acquisition of oil and gas properties, including the financial restructuring, reorganization and sale of companies. He was President of Enertec Corporation that was reorganized under Chapter 11 of the Bankruptcy Code in December 1994. In addition, Mr. Aikman is a director of the Panhandle Producers and Royalty Owners Association and a member of the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association and American Association of Petroleum Landmen. Mr. Aikman graduated from the University of Oklahoma in 1952.

Anthony V. Dub was elected to serve as a Director of the Company in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York City. Prior to forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston, an investment banking firm. Mr. Dub joined Credit Suisse First Boston in 1971 and was named a Managing Director in 1981. Mr. Dub received his Bachelor of Arts Degree from Princeton University in 1971.

Allen Finkelson, was appointed a Director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore since 1977, with the exception of the period from September 1983 through August 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson was first employed by Cravath, Swaine & Moore as an associate in 1971. Mr. Finkelson received his Bachelor of Arts Degree from St. Lawrence University and his Doctor of Laws Degree from Columbia University School of Law.

Ben A. Guill, was elected to serve as a Director of the Company in 1995. In September 1998 Mr. Guill joined First Reserve Corporation as President of its Houston office. First Reserve is a private equity firm, dedicated to the energy industry. Prior to joining First Reserve, Mr. Guill was a Partner and Managing Director of Simmons & Company International, an investment banking firm located in Houston, Texas, which focuses on the oil service and equipment industry. Mr. Guill had been with Simmons & Company since 1980. Prior to that Mr. Guill was with Blyth Eastman Dillon & Company from 1978 to 1980. Mr. Guill received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from the Wharton Graduate School of Business at the University of Pennsylvania.

Jonathan S. Linker has served as a Director of the Company since the Merger in August 1998. Mr. Linker has been a Managing Director of First Reserve since 1996, the President and a director of IDC Energy Corporation since 1987, and a Vice President and Director of Sunset Production Corporation since 1991. Mr. Linker earned a Bachelor of Arts degree in Geology from Amherst College, a Master of Arts degree in Geology from Harvard University and a Master of Business Administration degree from the Harvard Business School.

Eddie M. LeBlanc III, Senior Vice President and Chief Financial Officer joined the Company in January 2000. Previously Mr. LeBlanc was a founder of Interstate Natural Gas Company, which merged into Coho Energy in 1994. At Coho Energy Mr. LeBlanc served as Senior Vice President and Chief Financial Officer. Mr. LeBlanc's twenty-five years of experience include assignments in the oil and gas subsidiaries of Celeron Corporation and Goodyear Tire and Rubber. Prior to his industry experience, Mr. LeBlanc was with a national accounting firm, he is a certified public accountant, a chartered financial analyst, and holds a Bachelor's degree from University of Southwest Louisiana.

Herbert A. Newhouse, Senior Vice President – Gulf Coast, joined the Company in 1998. Prior to joining Range, Mr. Newhouse served as Executive Vice President of Domain Energy Corporation. He was a former Vice President of Tenneco Ventures Corporation. Mr. Newhouse was an employee of Tenneco for over 17 years and has 30 years of operational and managerial experience in oil and gas exploration and production. Mr. Newhouse received his Bachelor's degree in Chemical Engineering from Ohio State University.

Chad L. Stephens, Senior Vice President – Southwest, joined the Company in 1990. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer, since 1988. Prior thereto, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens received his Bachelor of Arts Degree in Finance and Land Management from the University of Texas.

Rodney L. Waller, Senior Vice President and Corporate Secretary joined Range in September 1999. Previously, Mr. Waller had been with Snyder Oil Corporation, now Santa Fe Snyder Corporation since 1977, where he served as a senior vice president. Before joining Snyder, Mr. Waller was employed by Arthur Andersen. Mr. Waller received his Bachelor of Arts degree from Harding University, and holds a certified public accountant designation.

Michael V. Ronca, Chief Operating Officer and a Director, joined the Company in 1998. Prior thereto, Mr. Ronca served as the President of Domain Energy Corporation. Mr. Ronca left the Company in February 2000.

*Catherine L. Sliva***,** Senior Vice President – Independent Producer Finance, joined the Company in connection with the Merger in August 1998. Prior to joining Range, Ms. Sliva served as Executive Vice President of Domain Energy Corporation. Ms. Sliva resigned her position with the Company in January 2000.

The Range Board has established three committees to assist in the discharge of its responsibilities.

Audit Committee. The Audit Committee reviews the professional services provided by Range’s independent public accountants and the independence of such accountants from management of Range. This Committee also reviews the scope of the audit coverage, the annual financial statements of Range and such other matters with respect to the accounting, auditing and financial reporting practices and procedures of Range as it may find appropriate or as have been brought to its attention. Messrs. Aikman, Dub and Guill are the members of the Audit Committee.

Compensation Committee. The Compensation Committee reviews and approves executive salaries and administers bonus, incentive compensation and stock option plans of Range. This Committee advises and consults with management regarding pensions and other benefits and significant compensation policies and practices of Range. This Committee also considers nominations of candidates for corporate officer positions. The members of the Compensation committee are Messrs. Aikman, Finkelson and Guill.

Executive Committee. The Executive Committee reviews and authorizes actions required in the management of the business and affairs of Range, which would otherwise be determined by the Board, where it is not practicable to convene the full Board. One of the principal responsibilities of the Executive Committee will be to review and approve smaller acquisitions. The members of the Executive Committee are Messrs. Edelman, Finkelson and Pinkerton.

ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Information with respect to executive compensation is incorporated herein by reference to the Company’s Proxy Statement for its 2000 annual meeting of stockholders.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information with respect to security ownership of certain beneficial owners and management is incorporated herein by reference to the Company’s Proxy Statement for its 2000 annual meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information with respect to certain relationships and related transactions is incorporated herein by reference to the Company’s Proxy Statement for its 2000 annual meeting of stockholders.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. and 2. Financial Statements and Financial Statement Schedules.
The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

3. Exhibits.
The items listed on the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Reports on Form 8-K.

The Company's Current Report on Form 8-K, dated October 15, 1999.

(c) Exhibits required by Item 601 of Regulation S-K.
Exhibits required to be filed by the Company pursuant to Item 601 of Regulation S-K are contained in Exhibits listed in response to Item 14 (a)3, and are incorporated herein by reference.

(d) Financial Statement Schedules Required by Regulation S-X.
The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Dated: March 20, 2000

RANGE RESOURCES CORPORATION

By: /s/ John H. Pinkerton

John H. Pinkerton
President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the persons on behalf of the Company and in the capacities and on the dates indicated.

/s/ Thomas J. Edelman March 20, 2000	Thomas J. Edelman, Chairman and Chairman of the Board
/s/ John H. Pinkerton March 20, 2000	John H. Pinkerton, Chief Executive Officer, President and Director
/s/ Eddie M. LeBlanc III March 20, 2000	Eddie M. LeBlanc III Chief Financial and Accounting Officer
/s/ Robert E. Aikman March 20, 2000	Robert E. Aikman, Director
/s/ Allen Finkelson March 20, 2000	Allen Finkelson, Director
/s/ Anthony V. Dub March 20, 2000	Anthony V. Dub, Director
/s/ Ben A. Guill March 20, 2000	Ben A. Guill, Director
/s/ Jonathan S. Linker March 20, 2000	Jonathan S. Linker, Director

GLOSSARY

The terms defined in this glossary are used throughout this report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet of natural gas equivalents, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

Credit Facility. The Range Resources Corporation $225 million revolving bank facility.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Infill well. A well drilled between known producing wells to better exploit the reservoir.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet per day.

Mcfe. One thousand cubic feet of natural gas equivalents, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

Merger. The acquisition via merger of Domain Energy Corporation by Lomak Petrolum, Inc. in August 1998. Simultaneously, Lomak's name was change to Range Resources Corporation.

Mmbbl. One million barrels of crude oil or other liquid hydrocarbons.

Mmbtu. One million British thermal units. One British thermal unit is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of natural gas equivalents.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net oil and gas sales. Oil and natural gas sales less oil and natural gas production expenses.

Oil and gas royalty trust. An arrangement whereby typically, the creating company conveys a net profits interest in certain of its oil and gas properties to the newly created trust and then distributes ownership units in the trust to its unitholders. The function of the trust is to serve as agent to distribute income from the net profits interest to its unitholders.

Present Value. The pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Productive well. A well that is producing oil or gas or that is capable of production.

Proved developed non-producing reserves. Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves. Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Recompletion. The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

Reserve life index. The presentation of proved reserves defined in number of years of annual production.

Royalty interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Term overriding royalty. A royalty interest that is carved out of the operating or working interest in a well. Its term does not extend to the economic life of the property and is of shorter duration than the underlying working interest. The term overriding royalties in which the Company participates through its Independent Producer Finance subsidiary typically extend until amounts financed and a designated rate of return have been achieved. At such point in time, the override interest reverts back to the working interest owner.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

RANGE RESOURCES CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES

(Item 14[a], [d])

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Exhibits

All other schedules have been omitted since the required information is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements or footnotes.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To The Board of Directors and Stockholders Range Resources Corporation

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (a Delaware corporation) as of December 31, 1998 and 1999, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 1999. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Range Resources Corporation as of December 31, 1998 and 1999, and the results of its operations and its cash flows for the three years in the period ended December 31, 1999, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Cleveland, Ohio

February 18, 2000

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS
(In thousands, except per share data)

	December 31, 1998	December 31, 1999
Assets		
Current assets		
Cash and equivalents	$ 10,954	$ 12,937
Accounts receivable	30,384	21,646
IPF receivables (Note 4)	7,140	12,500
Marketable securities	3,258	2,145
Assets held for sale (Note 5)	51,822	19,660
Inventory and other	3,373	4,051
	106,931	72,939
IPF receivables, net (Note 4)	70,032	52,913
Oil and gas properties, successful efforts method	935,822	978,919
Accumulated depletion and impairment	(273,723)	(383,622)
	662,099	595,297
Transportation, processing and field assets	89,471	33,777
Accumulated depreciation	(15,146)	(10,572)
	74,325	23,205
Other	8,225	8,015
	$ 921,612	$ 752,368
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 28,163	$ 23,925
Accrued liabilities	15,773	12,305
Accrued payroll and benefit costs	5,156	3,769
Accrued interest	9,439	8,635
Accrued business restructuring costs (Note 13)	2,697	—
Current portion of debt (Note 6)	55,187	5,014
	116,415	53,648
Senior debt (Note 6)	311,875	135,000
Non-recourse debt (Note 6)	60,100	142,520
Subordinated notes (Note 6)	180,000	176,360
Commitments and contingencies (Note 8)		
Company-obligated preferred securities of subsidiary trust (Note 9)	120,000	117,669
Stockholders' equity (Notes 9 and 10)		
Preferred stock, $1 Par, 10,000,000 shares authorized, $2.03 convertible preferred, 1,149,840 issued and outstanding (liquidation preference $28,746,000)	1,150	1,150
Common stock, $.01 par, 50,000,000 shares authorized, 35,933,523 and 37,901,789 issued	359	379
Capital in excess of par value	334,817	340,279
Retained deficit	(203,396)	(214,630)
Other comprehensive income (loss)	292	(7)
	133,222	127,171
	$ 921,612	$ 752,368

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31,		
	1997	1998	1999
Revenues			
Oil and gas sales	$130,017	$ 135,593	$145,492
Transportation, processing and marketing	7,806	6,711	7,770
IPF income, net of allowances	—	4,370	7,872
Interest and other	7,594	2,255	40,230
	145,417	148,929	201,364
Expenses			
Direct operating	31,481	39,001	43,074
IPF expense	—	7,996	5,825
Exploration	2,527	11,265	2,409
General and administrative	5,290	9,215	8,028
Interest	27,175	40,642	47,085
Depletion, depreciation and amortization	55,407	60,153	76,447
Provision for impairment (amounts include $37.7 million and $21.0 million related to assets held for sale in 1998 and 1999, respectively)	58,700	207,128	27,118
Business restructuring costs (Note 13)	—	3,147	—
	180,580	378,547	209,986
Income (loss) before taxes	(35,163)	(229,618)	(8,622)
Income taxes			
Current	684	278	1,601
Deferred	(12,515)	(54,746)	—
	(11,831)	(54,468)	1,601
Income (loss) before extraordinary item	(23,332)	(175,150)	(10,223)
Extraordinary item			
Gain on retirement of securities (Note 18)	—	—	2,430
Net income (loss)	$ (23,332)	$(175,150)	$ (7,793)
Comprehensive income (loss) (Note 2)	$ (24,524)	$(175,260)	$ (8,566)
Earnings (loss) per common share before extraordinary item: (Note 14)			
Basic	$ (1.31)	$ (6.82)	$ (0.34)
Dilutive	$ (1.31)	$ (6.82)	$ (0.34)
Earnings (loss) per common share after extraordinary item: (Note 14)			
Basic	$ (1.31)	$ (6.82)	$ (0.27)
Dilutive	$ (1.31)	$ (6.82)	$ (0.27)

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Preferred Stock		Common Stock				
	Shares	Par Value	Shares	Par Value	Capital in Excess of Par Value	Retained Earnings (Deficit)	Other Comprehensive Income (loss)
Balance, December 31, 1996	1,150	$1,150	14,751	$148	$110,248	$ 5,291	$ 692
Preferred dividends	—	—	—	—	—	(2,334)	—
Common dividends at $.10 per share	—	—	—	—	—	(2,037)	—
Common issued	—	—	6,307	63	107,293	—	—
Common repurchased	—	—	—	—	(107)	—	—
Compensation in connection with stock options	—	—	—	—	197	—	—
Unrealized loss on investments	—	—	—	—	—	—	(322)
Net loss	—	—	—	—	—	(23,332)	—
Balance, December 31, 1997	1,150	1,150	21,058	211	217,631	(22,412)	370
Preferred dividends	—	—	—	—	—	(2,334)	—
Common dividends at $.12 per share	—	—	—	—	—	(3,500)	—
Common issued	—	—	15,276	152	120,188	—	—
Common repurchased	—	—	(401)	(4)	(3,002)	—	—
Unrealized loss on investments	—	—	—	—	—	—	(78)
Net loss	—	—	—	—	—	(175,150)	—
Balance, December 31, 1998	1,150	1,150	35,933	359	334,817	(203,396)	292
Preferred dividends	—	—	—	—	—	(2,334)	—
Common dividends at $.03 per share	—	—	—	—	—	(1,107)	—
Common issued	—	—	1,270	13	2,113	—	—
Convertible securities conversion	—	—	699	7	3,349	—	—
Unrealized loss on investments	—	—	—	—	—	—	(299)
Net loss	—	—	—	—	—	(7,793)	—
Balance, December 31, 1999	1,150	$1,150	37,902	$379	$340,279	$(214,630)	$ (7)

See accompanying notes.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	1997	1998	1999
Cash flows from operations:			
Net (loss)	$ (23,332)	$(175,150)	$ (7,793)
Adjustments to reconcile net (loss) to net cash provided by operations:			
Depletion, depreciation and amortization	55,407	60,153	76,447
Provision for impairment	58,700	207,128	27,118
Valuation reserve of IPF receivables	—	5,918	3,962
Amortization of deferred offering costs	999	1,293	1,333
Deferred income taxes	(12,541)	(54,746)	—
Changes in working capital net of effects of acquired businesses:			
Accounts receivable	(11,079)	2,842	8,738
Marketable securities	(7,964)	(253)	(35)
Inventory and other	(1,981)	6,996	(1,958)
Accounts payable	17,825	(4,274)	(7,560)
Accrued liabilities	9,186	(3,068)	(8,355)
Gain on sale of assets and other	(8,154)	(1,817)	(39,280)
Net cash provided by operations	77,066	45,022	52,617
Cash flows from investing:			
Acquisition of businesses, net of cash	—	(41,170)	—
Investment in Great Lakes	—	—	96,285
Oil and gas properties	(492,259)	(135,399)	(25,093)
Additions to property and equipment	(64,945)	(3,732)	(656)
IPF investments of capital	—	(12,649)	(5,362)
IPF repayments of capital	—	3,556	13,160
Proceeds on sale of assets	56,070	17,081	17,476
Net cash provided by (used in) investing	(501,134)	(172,313)	95,810
Cash flows from financing:			
Proceeds from indebtedness	246,025	135,788	—
Repayments of indebtedness	(26)	(413)	(145,129)
Preferred stock dividends	(2,334)	(2,334)	(2,334)
Common stock dividends	(2,037)	(3,500)	(1,107)
Proceeds from trust preferred securities issuance, net	115,999	—	—
Proceeds from common stock issuance, net	67,648	1,985	2,152
Repurchase of common stock	(107)	(3,006)	(26)
Net cash provided by (used in) financing	425,168	128,520	(146,444)
Change in cash	1,100	1,229	1,983
Cash and equivalents at beginning of period	8,625	9,725	10,954
Cash and equivalents at end of period	$ 9,725	$ 10,954	$ 12,937
Supplemental disclosures of non-cash investing and financing activities:			
Purchase of property and equipment financed with common stock	$ 39,537	$ 116,469	$ —
Common stock issued in connection with benefit plans	398	1,887	1,783
Common stock exchanged for convertible securities	—	—	2,978

See accompanying notes.

RANGE RESOURCES CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation ("Range" or the "Company") is an independent oil and gas company engaged in development, exploration and acquisition primarily in three core areas: Southwest, Gulf Coast and Appalachia. In addition, through its IPF subsidiary, the Company provides financing to smaller independent oil and gas producers by purchasing term overriding royalty interests in oil and gas properties. Historically, the Company has increased its reserves and production through acquisitions, development and exploration. In pursuing this strategy, the Company has concentrated its activities in selected geographic areas. In each core area, the Company has established operating, engineering, geoscience, marketing and acquisition expertise.

In August 1998, the stockholders of the Company approved the acquisition via merger (the "Merger") of Domain Energy Corporation ("Domain"). Pursuant to the Merger, stockholders of Domain received approximately 13.6 million shares of the Company's Common Stock. The Company also purchased 3.8 million Domain shares for $50.5 million in cash. As a result of the Merger, Domain became a wholly-owned subsidiary of Range.

In September 1999, Range and FirstEnergy Corp. ("FirstEnergy") each contributed all of their Appalachia oil and gas properties and associated gas gathering and transportation systems to Great Lakes Energy Partners ("Great Lakes"). In addition, Range contributed $188.3 million of indebtedness and FirstEnergy contributed $2.0 million in cash. Great Lakes expects to increase production by active development of existing fields and exploitation of deeper formations. In addition, Great Lakes intends to pursue acquisition opportunities in Appalachia. Range and FirstEnergy each retained a 50% ownership interest in Great Lakes and share management responsibilities.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying financial statements include the accounts of the Company, all majority owned subsidiaries and its pro rata share of the assets, liabilities, income and expenses of certain oil and gas partnerships and joint ventures. Highly liquid temporary investments with an initial maturity of ninety days or less are considered cash equivalents.

Revenue Recognition

The Company recognizes revenues from the sale of its respective products in the period delivered. Revenues for services are recognized in the period the services are provided. Revenues for IPF are recognized in the period collected.

Marketable Securities

The Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Under Statement No. 115, debt and marketable equity securities are required to be classified in one of three categories: trading, available-for-sale, or held to maturity. The Company's equity securities qualify under the provisions of Statement No. 115 as available-for-sale. Such securities are recorded at fair value, and unrealized holding gains and losses, net of the related tax effect, are reflected in Stockholders' Equity as a separate component of comprehensive income. A decline in the market value of an available-for-sale security below cost that is deemed other than temporary is charged to earnings and results in the establishment of a new cost basis for the security. Realized gains and losses are determined on the specific identification method and are reflected in income.

Great Lakes

As described in Note 1, the Company contributed all of its Appalachia oil and gas properties and gas gathering and transportation systems to Great Lakes in September 1999. Great Lakes' reserves include proved reserves of approximately 440 Bcfe as of December 31, 1999, of which 84% is natural gas, 4,700 miles of gas gathering and transportation lines and a leasehold position of nearly one million gross acres. The joint venture owns interest in over 1,400 proved drilling locations within existing fields and has a reserve life index of 17.8 years. The Company consolidates its pro rata interest in the joint venture's assets and liabilities based upon its 50% ownership in Great Lakes.

Independent Producer Finance

Through IPF, Range acquires dollar denominated term overriding royalty interests in oil and gas properties owned by independent oil and gas producers. The Company accounts for the acquired term overriding royalty interests as receivables because the funds advanced to a producer for these interests are repaid from an agreed upon share of cash proceeds from the sale of production until the amount advanced plus a specified rate of return is paid. Only the rate of return portion of payments received from a producer is recognized as IPF income on the statement of income. The remaining cash receipts are recorded as a reduction in receivables on the balance sheet and as a return of capital on the statement of cash flows. The portion of the term overriding royalty interests classified as a current asset are those expected to be received as repayments over the next twelve month period. Periodically, the Company performs a review for possible uncollectible accounts receivable and provides for unrecoverable amounts in its allowance for uncollectible receivables. At December 31, 1999 the Company's allowance for uncollectible receivables totaled $17.3 million. During 1999, IPF expenses were comprised of $1.5 million of general and administrative expenses and $4.3 million of interest expense. During 1998, IPF expenses were comprised of $.5 million general and administrative expenses, $1.6 million of interest expense and a $5.9 million allowance against its portfolio of receivables.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas properties. Exploratory costs are capitalized pending determination of whether the well has found proved reserves. Exploratory costs which result in the discovery of proved reserves and the cost of development wells are capitalized. In the absence of a determination as to whether the reserves found from an exploratory well can be classified as proved, the costs of drilling such an exploratory well are not carried as an asset for more than one year following the completion of drilling. Geological and geophysical costs, delay rentals and costs to drill unsuccessful exploratory wells are expensed. Depletion is provided on the unit-of-production method. Oil is converted to Mcfe at the rate of 6 Mcf per barrel. The depletion rates per Mcfe were $1.03, $.89 and $1.04 in 1997, 1998 and 1999, respectively. Approximately $111.2 million, $75.9 million and $61.8 million of oil and gas properties were unproved as of December 31, 1997, 1998 and 1999, respectively.

The Company has adopted SFAS No. 121 "Accounting for the Impairment of Long-Lived Assets", which establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles and goodwill. SFAS No. 121 requires a review for impairment whenever circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability during 1997, 1998 and 1999, the Company recorded provisions for impairment of $58.7 million, $196.8 million and $6.1 million respectively, which reduced the carrying value of certain oil and gas properties to what the Company estimates to have been their fair value at that time. The provisions for impairment on the oil and gas properties were due to reserve revisions as a result of drilling results and declines in oil and gas prices in 1998 and 1999 and due to declines in oil and gas prices in 1997. The proved impairment was estimated determined based on the difference between the carrying amount of the assets and the present value of the future cash flows from proved properties discounted at 10%. Impairment is recognized only if the carrying amount of a property is greater than its expected undiscounted future cash flows. It is reasonably possible that a change in reserve or price estimates could occur in the near term and adversely impact management’s estimate of future cash flows and consequently the carrying value of the properties. The following are the proved properties impaired during 1998 (in thousands):

Property	Impairment Amount
Sonora properties	$ 65,712
Permian properties	1,018
West Texas properties	1,506
West Delta	16,117
Michigan properties	14,644
East Texas properties	2,323
Matagorda Island	15,643
Mobile Bay	10,735
East & West Cameron	19,905
	$147,603

Unproved properties are assessed periodically to determine whether there has been a decline in value. If such decline is indicated, a loss is recognized. The Company compares the carrying value of its unproved properties to the present value of the future cash flows of unproved properties discounted at 10% or considers such other information the Company believes is relevant in evaluating the properties’ fair value. Such other information may include the Company’s geological assessment of the area, other acreage purchases in the area, or the properties’ uniqueness. The present value of future cash flows from such properties has been adjusted for the Company’s assessment of risk related to the unproved properties. In assessing the risk associated with unproved properties, the Company considers the recoverability of unproved reserves that have been classified as probable and possible reserves. Probable reserves are reserves not reasonably certain or proved, yet are “more likely to be recovered than not.” Possible reserves are reasonably possible but “less likely to be recovered than not.” The following are the unproved properties impaired during 1998 (in thousands):

Property	Impairment Amount
Sonora unproved acreage	$20,089
Offshore unproved acreage	9,177
South Texas unproved acreage	19,922
	$49,188

Of the total impairment of $196.8 million, 55% was due to downward reserve revisions due to poor performance and drilling results and 45% was due to the decline in oil and gas prices. The impairment of oil and gas properties recorded in 1998 was based on estimates of future cash flows for each property in the two categories evaluated for impairment: proved properties and unproved properties. The impairment evaluation for proved properties utilized only proved reserves and the impairment evaluation for unproved properties utilized only unproved reserves. Future cash flows include revenues from anticipated oil and natural gas production, severance taxes, direct operating costs and capitalized costs.

The following is a table of index prices used in the calculation of the revenues estimated from oil and natural gas production over the anticipated life of the properties. These prices were then adjusted for the effect of the Company’s production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges.

Year	Oil prices	Gas prices
1999	$ 12.62–13.25	$ 1.94-2.25
2000	14.50 – 16.00	2.23 - 2.30
2001	15.60 – 16.50	2.30 - 2.37
2002	16.44 – 17.10	2.35 - 2.44
2003	17.00 – 17.61	2.40 - 2.51
2004	17.50 – 18.14	2.45 - 2.59
2005	17.90 – 18.69	2.50 - 2.67
2006	18.35 – 19.25	2.58 - 2.75
2007	18.81 – 19.82	2.63 - 2.83
2008	19.28 – 20.42	2.69 - 2.91
2009	19.76 – 21.03	2.75 - 3.00

During 1999, the Company recorded a $6.1 million impairment of unproved acreage in the Gulf of Mexico, due to further evaluations based on updated production and technical data indicating a reduction in the number of economic drilling locations. The amount of impairment was calculated by determining fair value at December 31, 1999 using management’s best estimate of discounted future net cash flows, as described above.

Transportation, Processing and Field Assets

The Company’s gas gathering systems and gas processing plant are in proximity to its principal gas properties. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from four to fifteen years. In September 1999, the Company decided to sell its gas processing plant and certain related assets. See Note 5 — Assets Held For Sale.

The Company receives fees for providing field related services. These fees are recognized as earned. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from one to five years, except buildings which are being depreciated over seven to twenty-five year periods.

Security Issuance Costs

Expenses associated with the issuance of the 6% Convertible Subordinated Debentures due 2007, the 8.75% Senior Subordinated Notes due 2007 and the 5 3/4% Trust Convertible Preferred Securities and the Company’s recourse and non-recourse debt are included in Other Assets on the accompanying balance sheets and are being amortized on the interest method over the term of the securities.

Gas Imbalances

The Company uses the sales method to account for gas imbalances. Under the sales method, revenue is recognized based on cash received rather than the proportionate share of gas produced. Gas imbalances at year end 1997, 1998 and 1999 were not material.

Comprehensive Income

The Company has adopted SFAS No. 130 “Reporting Comprehensive Income” which requires disclosure of comprehensive income and its components. Comprehensive income is defined as changes in stockholders’ equity from nonowner sources and, for the Company, includes net income and changes in the fair value of marketable securities. The following is a calculation of the Company’s comprehensive income for the years ended December 31, 1997, 1998 and 1999.

	Year Ended December 31,		
	1997	**1998**	**1999**
Net income (loss)	$(23,332)	$(175,150)	$(7,793)
Add: Change in unrealized gain/(loss)			
Gross	(322)	(78)	(299)
Tax effect	109	19	—
Less: Realized gain/(loss)			
Gross	(1,473)	(66)	(474)
Tax effect	494	15	—
Comprehensive income (loss)	$(24,524)	$(175,260)	$(8,566)

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Nature of Business

The Company operates in an environment with many financial and operating risks, including, but not limited to, the ability to acquire additional economically recoverable oil and gas reserves, the inherent risks of the search for, development of and production of oil and gas, the ability to sell oil and gas at prices which will provide attractive rates of return, and the highly competitive nature of the industry and worldwide economic conditions. The Company’s ability to expand its reserve base and diversify its operations is also dependent upon obtaining the necessary capital through operating cash flow, borrowings or the issuance of additional equity.

Recent Accounting Pronouncements

The Financial Accounting Standards Board has issued Statement of Financial Accounting Standards (“SFAS”) No. 133, Accounting for Derivative Instruments and Hedging Activities, which is effective for fiscal years beginning after June 15, 2000.

SFAS No. 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It also requires that an entity recognize all derivatives as either assets or liabilities on the balance sheet and measure those items at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to change in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of a forecasted transaction or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency-denominated forecasted transaction. The Company plans to adopt SFAS No. 133 during the first quarter of the year ended December 31, 2001 and is currently evaluating the effects of this pronouncement.

Reclassifications

Certain reclassifications have been made to prior periods presentation to conform with current period classifications.

(3) ACQUISITIONS

All acquisitions have been accounted for as purchases. The purchase prices were allocated to the assets acquired based on the estimated fair value of such assets and liabilities at the respective acquisition dates. The acquisitions were funded by working capital, advances under a revolving credit facility and the issuance of debt and equity securities.

In March 1998, oil and gas properties in the Powell Ranch Field in West Texas (the “Powell Ranch Properties”) were acquired for a purchase price of $60 million, comprised of $54.6 million in cash and $5.4 million of Common Stock.

As described in Note 1, the Company completed the Merger for a purchase price of $161.6 million, comprised of $50.5 million in cash and $111.1 million of Common Stock. Domain’s principal assets included oil and gas operations primarily onshore in the Gulf Coast and in the Gulf of Mexico, as well as, IPF.

In addition to the above mentioned acquisitions, the Company purchased various other properties for consideration of $2.7 million and $0.8 million during the years ended December 31, 1998 and 1999, respectively.

Unaudited Pro Forma Financial Information

The following table presents unaudited pro forma operating results as if certain transactions had occurred at the beginning of each period presented. The pro forma operating results include the acquisition of the Powell Ranch properties, the Domain merger and the Great Lakes transaction.

	Year ended December 31,	
	1998	1999
Revenues	$ 175,313	$194,615
Net income (loss)	(170,064)	(5,602)
Earnings (loss) per share — basic	(4.89)	(0.21)
Earnings (loss) per share — dilutive	(4.89)	(0.21)
Total assets	822,101	752,368
Stockholders’ equity	133,220	127,171

The pro forma operating results have been prepared for comparative purposes only. They do not purport to present actual operating results that would have been achieved had the acquisitions and financings been made at the beginning of each period presented or to necessarily be indicative of future results of operations.

(4) IPF RECEIVABLES

At December 31, 1998 and 1999, IPF had net receivables of $77.2 million and $65.4 million, respectively. The receivables result from the Company’s purchase of production payments in the form of term overriding royalty interests in exchange for an agreed upon share of revenues from identified properties until the amount invested and a specified rate of return on investment is paid in full. IPF’s overriding royalty interest constitutes a property interest that serves as security for the receivables. The Company has estimated that $12.5 million of receivables at December 31, 1999 will be repaid in the next twelve months and has classified such receivables as current assets. The net outstanding receivables include an allowance for uncollectible receivables of $14.0 million and $17.3 million at December 31, 1998 and 1999, respectively.

(5) ASSETS HELD FOR SALE

At December 31, 1999, assets held for sale consisted of the Company’s gas processing plant and associated assets located in the Permian Basin. In connection with the 1999 plan of disposal, the Company determined that the carrying value of the gas processing plant exceeded its fair value. Accordingly, an impairment loss of $21.0 million representing the excess of the carrying value over the fair value was recognized in 1999.

Fair value was determined by reference to the present value of the estimated future cash inflows of the gas processing plant. The impairment estimate on the gas processing plant recorded in the third quarter 1999 was based on estimates of future cash flows for the property. Future cash flows include revenues from residue gas, plant liquids and by-products derived from both equity and third party proved natural gas reserves, which are estimated to pass through the plant, direct operating costs and capitalized costs. The Company used estimated future gas prices by referencing ten year future strip prices in the calculation of the plant revenues estimated over the anticipated life of the property. These prices were then adjusted for the effect of the estimated throughput production, subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the date of the impairment charge.

Operating costs and capital costs were estimated based on the Company’s historical operating experience. These costs and expenses were adjusted for changes in variable costs attributable to changes in estimated throughput volumes. The impairment estimate was determined based on the difference between the carrying value of the plant and the present value of future cash flows discounted at 10%. It is reasonably possible that a change in reserve or price estimates could occur in the near term and adversely impact management's estimate of future cash flows and consequently the carrying value of property.

At December 31, 1998, assets held for sale primarily consisted of oil and gas properties located in South Texas and in the Gulf of Mexico. The Company entered into agreements with an independent firm to assist it in selling these assets. The assets were recorded at the lower of cost or estimated market value of the properties as assets held for sale in the current asset section of the Consolidated Balance Sheets. Of the $51.8 million of assets held for sale at December 31, 1998, $10.0 million of properties were sold for $9.2 million, with the remainder transferred back to oil and gas properties with depletion reinstated.

(6) INDEBTEDNESS

The Company had the following debt outstanding as of the dates shown. Interest rates at December 31, 1999 are shown parenthetically (in thousands):

	December 31,	
	1998	**1999**
Senior debt		
Credit Facility (8.7%)	$365,175	$140,000
Other (6.2%)	1,887	14
	367,062	140,014
Less amounts due within one year	55,187	5,014
Senior debt, net	$311,875	$135,000
Non-recourse debt		
Great Lakes (8.2%)	$ —	$ 95,020
IPF (8.7%)	60,100	47,500
Non-recourse debt	$ 60,100	$142,520
Subordinated notes		
8.75% Senior Subordinated Notes due 2007	$125,000	$125,000
6% Convertible Subordinated Debentures due 2007	55,000	51,360
Subordinated notes	$180,000	$176,360

The Company maintains a $225 million revolving bank facility (the "Credit Facility"). The Credit Facility provides for a borrowing base, which is subject to semi-annual redeterminations. The Credit Facility is secured by the Company's oil and gas properties. On March 13, 2000, the borrowing base on the Credit Facility was $160 million of which $16 million was available. The borrowing base is subject to semi-annual redetermination and certain other redeterminations based upon a variety of factors, including the discounted present value of estimated future net cash flow from oil and gas production. At the Company's option, loans may be prepaid and the revolving credit commitment may be reduced, in whole or in part at anytime in certain minimum amounts. The next redetermination occurs on April 1, 2000. If amounts outstanding at April 1, 2000 exceed the redetermined borrowing base, one-half of the excess, if any, must be repaid within 90 days and the remaining excess, if any, must be repaid within 180 days. Any borrowing base in excess of $135 million requires the approval of all lenders. There can be no assurance that a redetermined borrowing base will be in excess of $135 million. Therefore, the Company has classified as current the difference between the amount outstanding on December 31, 1999, and $135 million. A similar appropriate amount will be included in current portion of long term debt at March 31, 2000, unless an amended or replacement credit facility is entered into. Interest is payable quarterly or as

LIBOR notes mature and the loan matures in February 2003. Upon selling the Sterling gas plant, the Company currently plans to use all the net proceeds to reduce the balance outstanding under the Credit Facility. The Credit Facility provides that the borrowing base will be reduced by 67% of the net proceeds of the sale of the Sterling gas plant. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50% depending upon the percentage of the borrowing base drawn. The interest rate on the Credit Facility is LIBOR plus between 1.50% and 2.25%, depending upon amounts outstanding. The weighted average interest rates on these borrowings were 6.7% and 7.1% for the years ended December 31, 1998 and 1999, respectively.

The Company pro rata consolidates 50% of amounts outstanding under the $275 million revolving bank facility (the “Great Lakes Facility”) through its participation in Great Lakes. The Great Lakes Facility is non-recourse to Range. The Great Lakes Facility provides for a borrowing base, which is subject to semi-annual redeterminations. The Great Lakes Facility is secured by the Great Lakes oil and gas properties. On March 13, 2000, the borrowing base on the Great Lakes Facility was $191 million of which $9 million was available. The borrowing base reduces to $190 million at April 1, 2000. The borrowing base is subject to a semi-annual borrowing review on April 1, 2000. The redetermined borrowing base on April 1, 2000 requires the approval of all lenders. Interest is payable quarterly or as LIBOR notes mature and the loan matures in September 2002. The interest rate on the Great Lakes Facility is LIBOR plus between 1.50% and 2.00%, depending upon amounts outstanding. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50% depending upon the percentage of the borrowing base drawn. The weighted interest rate on this borrowing was 7.68% for the year ended December 31, 1999.

IPF has a $100 million revolving credit facility (the “IPF Facility”) through which it finances its activities. The IPF Facility is non-recourse to Range. The IPF Facility matures in December 2002 at which time all amounts owed thereunder are due and payable. The IPF Facility is secured by substantially all of IPF’s assets. The borrowing base under the IPF Facility is subject to semi-annual redeterminations. On March 13, 2000, the borrowing base on the IPF Facility was $56 million of which $13.6 million was available. The IPF Facility bears interest at prime rate or interest at LIBOR plus between 1.75% to 2.25% depending upon the total amounts outstanding. Interest expense on the IPF Facility is included in IPF expenses on the Consolidated Statements of Operations and amounted to $1.5 million and $4.3 million for the years ended December 31, 1998 and 1999, respectively. A commitment fee is paid quarterly on the average undrawn balance at a rate of 0.375% to 0.50%. The weighted average interest rate on these borrowings was 7.79% and 6.99% for the years ended December 31, 1998 and 1999, respectively.

The 8.75% Senior Subordinated Notes due 2007 (the “8.75% Notes”) are not redeemable prior to January 15, 2002. Thereafter, the 8.75% Notes are subject to redemption at the option of the Company, in whole or in part, at redemption prices beginning at 104.375% of the principal amount and declining to 100% in 2005. The 8.75% Notes are unsecured general obligations of the Company and are subordinated to all senior debt (as defined) including borrowings under the Credit Facility. The 8.75% Notes are guaranteed on a senior subordinated basis by the Company’s subsidiaries.

The 6% Convertible Subordinated Debentures Due 2007 (the “Debentures”) are convertible into shares of Common Stock at the option of the holder at any time prior to maturity. The Debentures are convertible at a conversion price of $19.25 per share, subject to adjustment in certain events. Interest is payable semi-annually in January and June. The Debentures mature in 2007 and are redeemable beginning on February 1, 2000 at a price of 104% of the face amount and declining 0.5% annually though 2007. The Debentures are unsecured general obligations and are subordinated to all senior indebtedness (as defined), which includes the 8.75% Notes and the Credit Facility. During 1999, $3.6 million of Debentures were retired at the election of the holders in exchange for approximately 496,000 shares of Common Stock. An extraordinary gain of $1.2 million was recorded as the Debentures were retired at a discount to their face value.

The debt agreements contain various covenants relating to net worth, working capital maintenance and financial ratio requirements. The Company is in compliance with these various covenants as of December 31, 1999. Interest paid on senior debt and subordinated notes during the year ended December 31, 1998 and 1999 totaled $39.6 million and $47.1 million, respectively. The Company does not capitalized any interest expense.

(7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES:

The Company’s financial instruments include cash and equivalents, accounts receivable, accounts payable, debt obligations, commodity and interest rate futures, options, and swaps. The book value of cash and equivalents, accounts receivable and payable and short term debt are considered to be representative of fair value because of the short maturity of these instruments. The Company believes that the carrying value of its borrowings under the Credit and IPF Facilities (collectively “the Bank Facilities”) approximate their fair value as they bear interest at rates indexed to LIBOR. In connection with the Merger, the IPF receivables were adjusted to what the Company estimates to have been their fair value at that time. The Company’s receivables are concentrated in the oil and gas industry. The Company does not view such a concentration as an unusual credit risk. Excluding IPF’s valuation allowances, the Company had recorded an allowance for doubtful accounts of $0.8 million and $1.5 million at December 31, 1998 and 1999, respectively.

A portion of the Company’s crude oil and natural gas sales are periodically hedged against price risks through the use of futures, option or swap contracts. The gains and losses on these instruments are included in the valuation of the production being hedged in the contract month and are included as an adjustment to oil and gas revenue. The Company also manages interest rate risk on its credit facility through the use of interest rate swap agreements. Gains and losses on interest rate swap agreements are included as an adjustment to interest expense.

The following table sets forth the book value and estimated fair values of the Company’s financial instruments:

	December 31, 1998		December 31, 1999	
	(In thousands)			
	Book Value	Fair Value	Book Value	Fair Value
Cash and equivalents	$ 10,954	$ 10,954	$ 12,937	$ 12,937
Marketable securities	2,966	3,258	2,152	2,145
Long-term debt	(607,162)	(607,162)	(458,894)	(458,894)
Commodity swaps	—	45	—	339
Interest rate swaps	—	(361)	—	704

At December 31, 1999, the Company had open hedges contracts for natural gas of 24.8 Bcf and 0.8 million barrels of oil. The swap contracts are at average prices ranging from $2.00 to $3.17 per Mcf and the oil contracts range from $19.01 to $25.00 per Bbl. While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate the contracts, was a net gain of approximately $0.3 million at December 31, 1999. These contracts expire monthly through December 2000. The gains or losses on the Company’s hedging transactions are determined as the difference between the contract price and the reference price, generally closing prices on the NYMEX. The resulting transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains or (losses) relating to these derivatives for the years ended December 31, 1997, 1998 and 1999 approximated $(.9) million, $3.1 million and $(10.6) million, respectively.

Interest rate swap agreements, which are used by the Company in the management of interest rate exposure, are accounted for on the accrual basis. Income and expense resulting from these agreements are recorded in the same category as interest expense arising from the related liability. Amounts to be paid or received under interest rate swap agreements are recognized as an adjustment to expense in the periods in which they accrue. At December 31, 1999, the Company had $80 million of borrowings subject to four interest rate swap agreements at rates of 5.35%, 4.82%, 5.64% and 5.59% through January 2000, September 2000, October 2000 and October 2000, respectively. The interest rate swaps may be extended at the counterparties' option for two years. The interest rate swap in effect through January 2000 was not extended at the option of the counterparty. The agreements require that the Company pay the counterparty interest at the above fixed swap rates and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. The closing 30-day LIBOR rate on December 31, 1999 was 6.49%. The fair value of the interest rate swap agreements at December 31, 1999, is based upon current quotes for equivalent agreements. As discussed in Note 6, the Company's Bank Facilities are based on LIBOR plus Applicable Margin (as defined).

These hedging activities are conducted with major financial or commodities trading institutions which management believes entail acceptable levels of market and credit risks. At times such risks may be concentrated with certain counterparties or groups of counterparties. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated.

(8) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims are likely to be resolved without material adverse effect on the Company's financial position or results of operations.

In May 1998, a Domain stockholder filed an action in the Delaware Court of Chancery, alleging that the terms of the Merger were unfair to a purported class of Domain stockholders and that the defendants (except Range) violated their legal duties to the class in connection with the Merger. Range is alleged to have aided and abetted the breaches of fiduciary duty allegedly committed by the other defendants. The action sought an injunction enjoining the Merger as well as a claim for money damages. In September 1998, the parties executed a Memorandum of Understanding (the "MOU"), which represents a settlement in principle of the litigation. Under the terms of the MOU, appraisal rights (subject to certain conditions) were offered to all holders of Domain common stock (excluding the defendants and their affiliates). Domain also agreed to pay any court-awarded attorneys' fees and expenses of the plaintiffs' counsel in an amount not to exceed $.3 million. The settlement in principle is subject to court approval and certain other conditions that have not been satisfied.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within 10 years and may be renewed by the Company. Rent expense under such arrangements totaled $0.6 million, $0.6 million and $1.1 million in 1997, 1998 and 1999, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

2000	$ 756
2001	695
2002	553
2003	195
2004	65
2005 and thereafter	—
	$2,264

(9) EQUITY AND TRUST SECURITIES

In October 1997, the Company, through a newly-formed affiliate Lomak Financing Trust (the “Trust”) completed the issuance of $120 million of 5 3/4% trust convertible preferred securities (the “Convertible Preferred Securities”). The Trust issued 2,400,000 shares of the Convertible Preferred Securities at $50 per share. Each Convertible Preferred Security is convertible at the holder’s option into 2.1277 shares of Common Stock, representing a conversion price of $23.50 per share. During 1999, $2.3 million of Convertible Preferred Securities were exchanged at the election of the holders for approximately 202,000 shares of Common Stock. An extraordinary gain of $1.2 million was recorded as the Convertible Preferred Securities were retired at a discount to their face value.

The Trust invested the $120 million of proceeds in 5 3/4% convertible junior subordinated debentures issued by Range (the “Junior Debentures”). In turn, Range used the net proceeds from the issuance of the Junior Convertible Debentures to repay a portion of its Credit Facility. The sole assets of the Trust are the Junior Debentures. The Junior Debentures and the related Convertible Preferred Securities mature on November 1, 2027. Range and the Trust may redeem the Junior Debentures and the Convertible Preferred Securities, respectively, in whole or in part, on or after November 4, 2000. For the first twelve months thereafter, redemptions may be made at 104.025% of the principal amount. This premium declines proportionally every twelve months until November 1, 2007, when the redemption price becomes fixed at 100% of the principal amount. If the Company redeems any Junior Debentures prior to the scheduled maturity date, the Trust must redeem Convertible Preferred Securities having an aggregate liquidation amount equal to the aggregate principal amount of the Junior Debentures so redeemed.

The Company has guaranteed the payments of distributions and other payments on the Convertible Preferred Securities only if and to the extent that the Trust has funds available. Such guarantee, when taken together with Range’s obligations under the Junior Debentures and related indenture and declaration of trust, provide a full and unconditional guarantee of amounts due on the Convertible Preferred Securities.

The Company owns all the common securities of the Trust. As such, the accounts of the Trust will be included in Range’s consolidated financial statements after appropriate eliminations of intercompany balances. The distributions on the Convertible Preferred Securities will be recorded as a charge to interest expense on Range’s Consolidated Statements of Operations, and such distributions are deductible by Range for income tax purposes.

In November 1995, the Company issued 1,150,000 shares of $2.03 convertible exchangeable preferred stock (the “$2.03 Preferred Stock”) for $28.8 million. The $2.03 Preferred Stock is convertible into the Company’s common stock at a conversion price of $9.50 per share, subject to adjustment in certain events. The $2.03 Preferred Stock is redeemable, at the option of the Company, at a price of $26.25 per share beginning November 1, 1998, declining $0.25 per share annually through 2003. At the option of the Company, the $2.03 Preferred Stock is exchangeable for the Company’s 8-1/8% Convertible Subordinated Notes due 2005. The notes would be subject to the same redemption and conversion terms as the $2.03 Preferred Stock.

(10) STOCK OPTION AND PURCHASE PLAN

The Company has four stock option plans, one stock incentive plan, as well as a stock purchase plan. Two of the stock option plans were adopted as a result of the Merger. Information with respect to these stock option plans is summarized as follows:

				Plans Adopted Via the Merger		
	1999 Incentive Plan	Option Plan	Director’s Plan	Option Plan	Director’s Plan	Total
Outstanding at December 31, 1998	—	2,042,757	140,000	938,976	19,340	3,141,073
Granted	60,000	904,150	40,000	—	—	1,004,150
Exercised	—	(70,000)	—	(374,264)	—	(444,264)
Expired/Cancelled	—	(380,425)	(12,000)	(1,445)	—	(393,870)
Outstanding at December 31, 1999	60,000	2,496,482	168,000	563,267	19,340	3,307,089

In May 1999, the shareholders approved the Company’s 1999 Stock Incentive Plan (the “Incentive Plan”) providing for the issuance of up to 1.4 million shares of common stock. The Incentive Plan is administered by the Compensation Committee of the Board. All options issued under the Incentive Plan vest 25% per year beginning one year after the grant date and expire 10 years from date of grant. During the year ended December 31, 1999, 60,000 options were granted at a price of $5.63 per share, none of which were exercisable.

Range maintains the 1989 stock option plan (“Option Plan”) which authorized the grant of options of up to 3.0 million shares of Common Stock, however, no new options will be granted under this plan. Under the Option Plan, incentive and non-qualified options have been issued to officers, employees and consultants. The Option Plan is administered by the Compensation Committee of the Board. All options issued under the Option Plan before September 1998 vest 30% after one year, 60% after two years and 100% after three years and expire 5 years from date of grant. Options issued after September 30, 1999 vest 25% per year beginning one year after the grant date and expire 10 years from date of grant. During the year ended December 31, 1999, 70,000 options were exercised and 380,425 were cancelled or expired. At December 31, 1999, 1,540,796 options were exercisable at prices ranging from $6.75 to $18.00 per share.

In 1994, the stockholders approved the 1994 Outside Directors Stock Option Plan (the “Directors Plan”). Only Directors who are not employees of the Company are eligible under the Directors Plan. The Directors Plan covers a maximum of 200,000 shares. During 1999, 40,000 options were granted at $4.81 and 12,000 were cancelled or expired. At December 31, 1999, 92,800 options were exercisable at prices ranging from $8.00 to $16.875 per share.

In connection with the merger, Range adopted the Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (the “Domain Option Plan”) and the Domain Energy Corporation 1997 Stock Option Plan for Nonemployee Directors (the “Domain Director Plan”). Subsequent to the Merger, no new options will be granted under the Domain Option and Director Plans and existing options are exercisable into shares of Range Common Stock. During the year ended December 31, 1999 options covering 356,812 shares were exercised at $0.01 per share and 17,452 shares were exercised at $3.46 per share. At December 31, 1999, 451,562 options were currently exercisable under the Domain Option Plan at $3.46 per share. The remaining 111,705 options have an exercise price of $0.01 per share and are currently exercisable. At December 31, 1999, options totaling 19,340 shares were outstanding and exercisable under the Domain Director Plan at $11.17 per share.

In June 1997, the stockholders approved the 1997 Stock Purchase Plan (the “1997 Plan”) which authorizes the sale of up to 900,000 shares of common stock to officers, directors, key employees and consultants. Under the 1997 Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted. Through December 31, 1999, no rights had been granted for less than 75% of market value. The Company previously had stock purchase plans which covered 833,333 shares. The previous stock purchase plans have been terminated. The 1997 Plan is administered by the Compensation Committee of the Board. From inception through December 31, 1999, a total of 516,897 registered shares had been sold through stock purchase plans, for a total consideration of approximately $2.9 million.

The Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, “Accounting for Stock Based Compensation.” Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost for the Corporation’s stock option plans been determined based on the fair value at the grant date for awards in 1997, 1998 and 1999 consistent with the provisions of SFAS No. 123, the Company’s net earnings and earnings per share would have been reduced to the pro forma amounts indicated below:

	1997	1998	1999
		(in thousands, except per share data)	
Net earnings (loss) — as reported	$(23,332)	$(175,150)	$(7,793)
Earnings (loss) per share — as reported	$ (1.31)	$ (6.82)	$ (0.27)
Earnings (loss) per share dilutive — as reported	$ (1.31)	$ (6.82)	$ (0.27)
Net earnings (loss) — pro forma	$(24,717)	$(176,569)	$(8,858)
Earnings (loss) per share —pro forma	$ (1.38)	$ (6.88)	$ (0.30)
Earnings (loss) per share dilutive—pro forma	$ (1.38)	$ (6.88)	$ (0.30)

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for 1997, 1998 and 1999, respectively: fair value of $1.15, $1.24 and $1.37 per share; dividend yields of $.10, $.12 and $.03 per share; expected volatility factors of .46, .79 and 3.55 risk-free interest rates of 6.5%; 4.75% and 5.1%; and a average expected life of 4 to 6 years.

(11) BENEFIT PLAN

The Company maintains a 401(K) Plan for the benefit of its employees. The Plan permits employees to make contributions on a pre-tax salary reduction basis. The Company makes discretionary contributions to the Plan. Company contributions for 1997, 1998 and 1999 were $0.7 million, $0.7 million and $0.9 million, respectively. The contributions were made with Range common stock, which was valued at market value on the date of the contribution.

(12) INCOME TAXES

Federal income tax provision (benefit) was $(11.8) million, $(54.7) million and $0 million for the years 1997, 1998 and 1999, respectively. The current portion of the income tax provision for 1999 represents state income tax currently payable. A reconciliation between the statutory federal income tax rate and the Company’s effective federal income tax rate is as follows:

	1997	1998	1999
Statutory tax rate	(34)%	(34)%	(34)%
Valuation allowance	—	10	34
State income tax	—	—	19
Effective tax rate	(34)%	(24)%	19%
Income taxes paid	$1,216,000	$36,000	$388,000

The Company follows FASB Statement No. 109, “Accounting for Income Taxes”. Under Statement 109, the liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Significant components of the Company's deferred tax liabilities and assets are as follows (in thousands):

	December 31,	
	1998	1999
Deferred tax liabilities:		
Depreciation	$ 30,232	$ 25,406
Deferred tax assets:		
Net operating loss carryforward	$ 51,810	$ 47,433
Percentage depletion carryforward	2,753	3,126
AMT credits and other	685	660
Total deferred tax assets	55,248	51,219
Valuation allowance for deferred tax assets	(25,016)	(25,813)
Net deferred tax assets	$ 30,232	$ 25,406
Net deferred tax liabilities	$ —	$ —

Utilization of the deferred tax asset of $25.8 million is dependent on future taxable profits being in excess of profits arising from existing taxable temporary differences. The Company has established a $25.8 million valuation allowance and has written down to zero its net deferred tax assets at December 31, 1999. Management believes sufficient uncertainty exists regarding its net deferred tax assets that a valuation allowance is required. Upon future realization of the deferred tax asset, $25.8 million of the valuation allowance will reduce the Company's future income tax expense.

The Company has entered into several business combinations accounted for as purchases. In connection with these transactions, deferred tax assets and liabilities of $7.7 million and $38.3 million respectively, were recorded. In 1998 the Company acquired Domain Energy Corporation in a taxable business combination accounted for as a purchase. A net deferred tax liability of $29 million was recorded in the transaction.

As a result of the Company's issuance of equity and convertible debt securities, it experienced a change in control during 1988 as defined by Section 382 of the Internal Revenue Code. The change in control and the Merger have placed limitations to the utilization of net operating loss carryovers. At December 31, 1999, the Company had available for federal income tax reporting purposes net operating loss carryovers of approximately $127 million which are subject to annual limitations as to their utilization and otherwise expire between 2000 and 2014, if unused. The Company has alternative minimum tax net operating loss carryovers of $113 million which are subject to annual limitations as to their utilization and otherwise expire from 2000 to 2014 if unused. The Company has statutory depletion carryover of approximately $4.9 million and an alternative minimum tax credit carryover of approximately $0.7 million. The statutory depletion carryover and alternative minimum tax credit carryover are not subject to limitation or expiration.

(13) BUSINESS RESTRUCTURING COSTS

In the fourth quarter of 1998, the Company initiated a restructuring plan to reduce costs and improve operating efficiencies. The restructuring plan included actions by the Company to close its Midland, Texas field office, eliminate certain geological and exploration positions, cancel certain exploration and drilling obligations, as well as consolidate certain administrative functions at the remaining locations. In connection with the restructuring plan, 54 employees were terminated. The terminated employees were comprised as follows: 33 in operations; 11 in exploration; 3 in Midland office; 3 in gas marketing; 2 in IPF; and 2 in investor relations. These employees were associated with operations that were consolidated or eliminated in response to the depressed energy price environment. Estimated employee termination costs of $2.1 million were accrued in 1998. Of the total number of employees affected, 42 were terminated in 1998.

In addition to the costs of terminating employees, the principal costs of the restructuring plan include the writedown of the carrying value of assets impaired due to the restructuring and lease and contract termination costs. The charge included $.6 million for estimated costs to exit lease and other contractual commitments and an additional $.4 million relating to costs associated with the closing of the Midland, Texas office, which was deemed to be uneconomical. The $.4 million of associated costs consisted of $.1 million of costs to exit the office lease and $.3 million of costs to exit two exploration agreements. The Midland office was responsible primarily for the operation of a portion of the Company’s Permian assets. The operation of these assets were consolidated in the Company’s Fort Worth, Texas office. At December 31, 1998 $2.7 million was accrued in connection with the restructuring plan. The plan was completed during 1999.

(14) EARNINGS PER COMMON SHARE

The following table sets forth the computation of earnings per common share and earnings per common share – assuming dilution (in thousands):

	1997	1998	1999
Numerator:			
Net (loss)	$(23,332)	$(175,150)	$ (7,793)
Preferred stock dividends	(2,334)	(2,334)	(2,334)
Numerator for earnings per common share	(25,666)	(177,484)	(10,127)
Effect of dilutive securities:			
Preferred stock dividends	—	—	—
Numerator for earnings per common Share – assuming dilution	$(25,666)	$(177,484)	$(10,127)
Denominator:			
Denominator for earnings per common Share – weighted average shares	19,641	26,008	36,933
Effect of dilutive securities:			
Employee stock options	—	—	—
Warrants	—	—	—
Dilutive potential common shares	—	—	—
Denominator for diluted earnings per share Adjusted weighted-average shares and Assumed conversions	19,641	26,008	36,933
(Loss) per common share	$ (1.31)	$ (6.82)	$ (0.27)
(Loss) per common share – assuming dilution	$ (1.31)	$ (6.82)	$ (0.27)

For additional disclosure regarding the Company’s Debentures, and the $2.03 Preferred Stock, see Notes 6, and 9 respectively. The Debentures were outstanding during 1997, 1998 and 1999 but were not included in the computation of diluted earnings per share because the stated conversion price was greater than the average market price of common shares and, therefore, the effect would be antidilutive. The $2.03

Preferred Stock was outstanding during 1997, 1998 and 1999 and was convertible into 3,026,316 of additional shares of common stock. The 3,026,316 additional shares were not included in the computation of diluted earnings per share because the conversion price was greater than the average market price of common shares and, therefore, the effect would be antidilutive. There were stock options outstanding during 1997, 1998 and 1999 which were exercisable, resulting in 642,720, 718,279 and 504,643 additional shares for common stock equivalents, respectively. These additional shares were not included in the 1997, 1998 or 1999 computations of diluted earnings per share because the effect was antidilutive.

In addition to further asset sales, the Company currently anticipates it will significantly increase its efforts to exchange Common Stock or other equity linked securities for its existing fixed rate securities or reduce debt and associated financing costs through some other substantial restructuring initiative. While the Company expects to exchange the fixed rate securities at a substantial discount to their face value, the Company’s existing common stockholders will be materially diluted if a material portion of the fixed rate securities are exchanged. The dilutive effect to the common stockholders will depend upon a number of factors, the primary ones being the number of shares and the price at which additional Common Stock is issued or the price which newly issued securities are convertible into Common Stock.

(15) MAJOR CUSTOMERS

The Company markets its oil and gas production on a competitive basis. The type of contract under which gas production is sold varies but can generally be grouped into three categories: (a) life-of-the-well; (b) long-term (1 year or longer); and (c) short-term contracts which may have a primary term of one year, but which are cancelable at either party’s discretion in 30-120 days. Approximately 22% of the Company’s gas production is currently sold under market sensitive contracts which do not contain floor price provisions. For the year ended December 31, 1999, no one customer accounted for 10% or more of the Company’s total oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the operations of the Company. Oil is sold on a basis such that the purchaser can be changed on 30 days notice. The price received is generally equal to a posted price set by the major purchasers in the area. The Company sells to oil purchasers on a basis of price and service.

Under an agreement with FirstEnergy, Great Lakes’ sells gas to FirstEnergy on a negotiated basis. Great Lakes may sell gas to third parties, however such arrangements are contracted through FirstEnergy, and FirstEnergy may elect to match any such arrangements.

(16) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to oil and gas producing activities:

	Year Ended December 31,		
	1997	**1998**	**1999**
		(in thousands)	
Oil and gas properties:			
Subject to depletion	$ 674,067	$ 859,911	$ 917,107
Unproved	111,156	75,911	61,812
Total	785,223	935,822	978,919
Accumulated depletion	(161,416)	(273,723)	(383,622)
Net oil and gas properties	$ 623,807	$ 662,099	$ 595,297
Costs incurred:			
Acquisition	$ 448,822	$ 286,974	$ 846
Development	56,430	71,793	33,808
Exploration	2,375	9,756	3,604
Total costs incurred	$ 507,627	$ 368,523	$ 38,258

The amount for costs incurred for acquisitions in 1999 does not reflect $68 million recorded as an equity interest in the Great Lakes joint venture associated with the Company’s 50% interest in the reserves contributed by FirstEnergy upon formation of the joint venture. The Company's share of the contributed reserves from FirstEnergy was 81.6 Bcfe.

(17) GAIN ON SALE

In September 1999, Range transferred all of its Appalachian oil and gas properties and associated gas gathering and transportation systems to Great Lakes in exchange for a non-controlling ownership interest. Additionally, the Company contributed $188.3 million of indebtedness to Great Lakes. The Great Lakes partners have no commitment to support the operations or related obligations of Great Lakes. In connection with the transfer, Range recognized a gain of $39.8 million, which was attributable to the portion of the net assets conveyed to Great Lakes in excess of the Company's 50% ownership interest. The gain was calculated by comparing the Company's estimate of the fair market value of the assets and liabilities conveyed to their net book value.

The estimated fair market value of oil and gas properties was based upon future net cash flows from the assets discounted 10% at September 30, 1999. The present value of future cash flows from such properties has been adjusted for the Company's assessment of risk related to the properties. For purposes of determining the fair market value of oil and gas properties, risk factors ranging from 20% to 60% were used depending on the nature of the reserve category. The Company assumed NYMEX prices of $19.00 per barrel of oil and $2.65 per mcf of gas for purposes of calculating future net cash flows. Prices were escalated 2.5% annually, with oil capped at the price of $30.00 per barrel and gas capped at the price of $5.00 per mcf. These prices were then adjusted for the effect of the Company's production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges. Severance taxes, direct operating costs and capitalized costs were estimated based on the Company's historical operating experience. These costs and expenses were escalated at 2.5% per year. These prices and costs were applied to production profiles developed by the Company's engineers using estimates of proved reserves and unproved reserves. The estimated fair market value of other assets contributed to Great Lakes was determined by an internally generated cash flow model which was developed to determine the future revenues and costs associated with these activities, discounted 10% annually. These discounted cash flows were risked individually at rates ranging between 30% and 60%.

During the year ended December 31, 1999, the Company sold various non-strategic properties. A net loss in the amount of $1.3 million was recognized on the sale of these properties due to their net book value being greater than proceeds received upon their sale.

(18) EXTRAORDINARY ITEM

During 1999, Range exchanged $2.3 million of Convertible Preferred Securities and $3.6 million of Debentures for approximately 699,000 shares of Common Stock. In connection with the exchange a $2.4 million extraordinary gain was recorded because the Convertible Preferred Securities and Debentures were retired at a discount to their face value.

(19) UNAUDITED SUPPLEMENTAL RESERVE INFORMATION

The Company's proved oil and gas reserves are located in the United States. Proved reserves are those quantities of crude oil and natural gas which, upon analysis of geological and engineering data, can with reasonable certainty be recovered in the future from known oil and gas reservoirs. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage.

Quantities of Proved Reserves

	Crude Oil (Bbls)	Natural Gas (Mcf)
	(in thousands)	
Balance, December 31, 1996	14,675	295,594
Revisions	(2,603)	(70,763)
Extensions, discoveries and additions	1,664	55,324
Purchases	18,541	339,447
Sales	(709)	(6,775)
Production	(1,794)	(38,409)
Balance, December 31, 1997	29,774	574,418
Revisions	(14,195)	(76,728)
Extensions, discoveries and additions	2,121	57,261
Purchases	15,332	140,120
Sales	(3,248)	(16,561)
Production	(2,655)	(45,193)
Balance, December 31, 1998	27,129	633,317
Revisions	1,294	(39,298)
Extensions, discoveries and additions	307	11,066
Purchases	5,241	51,751
Sales	(2,495)	(162,245)
Production	(2,659)	(50,808)
Balance, December 31, 1999	28,817	443,783

Proved developed reserves

	Crude Oil (Bbls)	Natural Gas (Mcf)
	(in thousands)	
December 31, 1997	14,971	369,786
December 31, 1998	19,649	436,062
December 31, 1999	17,884	299,436

The revisions which occurred during 1998 include 13,126 Mbbl of oil and 49,004 Mmcf of gas which became uneconomic due to lower commodity prices at December 31, 1998 as compared to December 31, 1997. The revisions which occurred during 1999 were based primarily on reservoir performance measures partially offset by some revisions upward for positive changes in commodity prices. The average prices used at December 31, 1999 to estimate the reserve information were $23.48 per barrel for oil, $15.69 per barrel for natural gas liquids and $2.34 per Mcf for gas using the benchmark NYMEX price of $25.60 per barrel and $2.33 per Mmbtu. The average prices at December 31, 1998 were $10.25 per barrel for oil, $6.61 per barrel for natural gas liquids and $2.34 per Mcf for gas using the benchmark NYMEX price of $12.38 per barrel and $2.25 per Mmbtu.

The “Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves” (Standardized Measure) is a disclosure requirement under Statement of Financial Accounting Standards No. 69 “Disclosures about Oil and Gas Producing Activities”. The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions, which are not taken into account in calculating the Standardized Measure.

Future cash inflows were estimated by applying year end prices to the estimated future production less estimated future production costs based on year end costs. Future net cash inflows were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Standardized Measure

	As of December 31,		
	1997	1998	1999
		(in thousands)	
Future cash inflows	$2,037,357	$1,744,653	$1,689,541
Future costs:			
Production	(512,657)	(513,119)	(486,618)
Development	(248,553)	(211,236)	(189,784)
Future net cash flows	1,276,147	1,020,298	1,013,139
Income Taxes	(280,189)	(104,500)	(131,529)
Total undiscounted future net cash flows	995,958	915,798	881,610
10% discount factor	(485,258)	(398,703)	(378,459)
Standardized measure	$ 510,700	$ 517,095	$ 503,151

Changes in Standardized Measure

	As of December 31,		
	1997	1998	1999
		(in thousands)	
Standardized measure, beginning of year	$ 350,889	$ 510,700	$ 517,095
Revisions:			
Prices	(210,429)	(138,985)	128,799
Quantities	(29,409)	(112,012)	(37,911)
Estimated future development cost	(37,788)	26,465	8,941
Accretion of discount	49,217	63,233	45,420
Income taxes	10,360	88,222	(14,307)
Net Revisions	(218,049)	(73,007)	130,942
Purchases	460,753	134,186	71,022
Extensions, discoveries and additions	55,751	35,169	16,354
Production	(93,865)	(87,668)	(77,884)
Sales	(14,406)	(26,197)	(136,491)
Changes in timing and other	(30,373)	23,982	(17,887)
Standardized measure, end of year	$ 510,700	$ 517,095	$ 503,151

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 14[a 3])

Exhibit No.	Description
3.1(a)	Certificate of Incorporation of Lomak dated March 24, 1980 (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
3.1(b)	Certificate of Amendment of Certificate of Incorporation dated July 22, 1981 (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
3.1(c)	Certificate of Amendment of Certificate of Incorporation dated September 8, 1982 (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
3.1(d)	Certificate of Amendment of Certificate of Incorporation dated December 28, 1988 (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
3.1(e)	Certificate of Amendment of Certificate of Incorporation dated August 31, 1989 (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
3.1(f)	Certificate of Amendment of Certificate of Incorporation dated May 30, 1991 (incorporated by reference to the Company’s Registration Statement (No. 333-20259)).
3.1(g)	Certificate of Amendment of Certificate of Incorporation dated November 20, 1992 (incorporated by reference to the Company’s Registration Statement (No. 333-20257)).
3.1(h)	Certificate of Amendment of Certificate of Incorporation dated May 24, 1996 (incorporated by reference to the Company’s Registration Statement (No. 333-20257)).
3.1(i)	Certificate of Amendment of Certificate of Incorporation dated October 2, 1996 (incorporated by reference to the Company’s Registration Statement (No. 333-20257)).
3.1(j)	Restated Certificate of Incorporation as required by Item 102 of Regulation S-T (incorporated by reference to the Company’s Registration Statement (No. 333-20257)).
3.1(k)	Certificate of Amendment of Certificate of Incorporation dated August 25, 1998 (incorporated by reference to the Company’s Registration Statement (No. 333-62439)).
3.2	By-Laws of the Company (incorporated by reference to the Company’s Registration Statement (No. 33-31558)).
4	Specimen certificate of Lomak Petroleum, Inc. (incorporated by reference to the Company’s Registration Statement (No. 333-20257)).
4.4	Certificate of Trust of Lomak Financing Trust (incorporated by reference to the Company’s Registration Statement (No. 333-43823)).
4.5	Amended and Restated Declaration of Trust of Lomak Financing Trust dated as of October 22, 1997 by The Bank of New York (Delaware) and the Bank of New York as Trustees and Lomak Petroleum, Inc. as Sponsor (incorporated by reference to the Company’s Registration Statement (No. 333-43823)).
4.6	Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company’s Registration Statement (No. 333-43823)).
4.7	First Supplemental Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company’s Registration Statement (No. 333-43823)).

4.8	Form of 5 3/4% Preferred Convertible Securities (included in Exhibit 4.5 above).
4.9	Form of 5 3/4% Convertible Junior Subordinated Debentures (included in Exhibit 4.7 above).
4.10	Convertible Preferred Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Preferred Guarantee Trustee (incorporated by reference to the Company's Registration Statement (No. 333-43823)).
4.11	Common Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Common Guarantee Trustee. (incorporated by reference to the Company's Registration Statement No. 333-43823)).
4.12	Purchase and Sale Agreement between Cometra Energy, L.P. and Cometra Production Company, L.P., as seller, and Lomak Petroleum, Inc., as buyer, dated December 31, 1996, including First Amendment to Purchase and Sale Agreement, dated January 10, 1997 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
4.13	Purchase and Sale Agreement between Rockland, L.P., as seller, and Lomak Petroleum, Inc., as buyer, dated December 31, 1996 (incorporated by reference on the Company's Registration Statement (No. 333-20257)).
4.14	Form of Trust Indenture relating to the Senior Subordinated Notes due 2007 between Lomak Petroleum, Inc., and Fleet National Bank as trustee (incorporated on the Company' s Registration Statement (No. 333-20257)).
4.15	Purchase and Sale Agreement dated as of September 8, 1997 by and among Cabot Oil & Gas Corporation, Cranberry Pipeline Corporation, Big Sandy Gas Company, and Lomak Petroleum, Inc. (incorporated by reference to the Company's Form 10-K dated March 20, 1998).
4.16	Agreement and Plan of Reorganization dated December 5, 1997 between Arrow Operating Company, Kelly W. Hoffman and L .S. Decker and Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement (No. 333-43823))
4.17	Credit Agreement, dated as of June 7, 1996, between Domain Finance Corporation and Compass Bank —Houston (including the First and the Second Amendment thereto) (incorporated by reference to Exhibit 10.3 of Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on April 4, 1997 and Exhibit 10.3 of Amendment No. 1 to Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on May 21, 1997) (File No. 333-24641).
10.1(a)	Incentive and Non-Qualified Stock Option Plan dated March 13, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(b)	Advisory Agreement dated September 29, 1988 between Lomak and SOCO (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(c)	401(k) Plan Document and Trust Agreement effective January 1, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(d)	1989 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(e)	Form of Directors Indemnification Agreement (incorporated by reference to the Company's Registration Statement (No. 333-47544)).
10.1(f)	1994 Outside Directors Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).
10.1(g)	1994 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).
10.1(h)	$400,000,000 Credit Agreement Among Lomak Petroleum, Inc., as Borrower, and the Several Lenders from Time to Time parties Hereto, including Bank One, Texas, N.A. as Administrative Agent, The Chase Manhattan Bank, as Syndication Agent, and Nationsbank of Texas, N.A., as Documentation Agent (incorporated by reference to the Company's Form 10-K dated February 7, 1997).

10.1(i)	Registration Rights Agreement dated October 22, 1997, by and among Lomak Petroleum, Inc., Lomak Financing Trust, Morgan Stanley & Co. Incorporated, Credit Suisse First Boston, Forum Capital markets L.P. and McDonald Company Securities, Inc., (incorporated by reference to the Company's Registration Statement (No. 333-43823)).
10.1(j)	Amendment to the Lomak Petroleum, Inc., 1989 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(k)	1997 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(l)	1997 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(m)	Fourth Amendment to $400,000,000 Credit Agreement dated January 27, 1999
10.1(n)	Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
10.1(o)	Domain Energy Corporation 1997 Stock Option Plan for Nonemployee Directors (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
10.1(p)	Employment Agreement, dated August 25, 1998, between the Company and Michael V. Ronca.
10.1(q)*	$100,000,000 Credit Agreement between Range Energy Finance Corporation, as Borrower, and Credit Lyonnais New York Branch, as Administrative Agent and Certain Lenders dated December 14, 1999.
21*	Subsidiaries of the Registrant.
23.1*	Consent of Independent Public Accountants.
23.2*	Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers.
23.3*	Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers.
23.4*	Consent of Wright and Company, independent consulting engineers.
27*	Financial Data Schedule.

* Filed herewith.